UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category; Proposed Rule 78 Fed. Reg. 34,432 (June 7, 2013)	Docket ID No. EPA–HQ–OW– 2009–0819; EPA–HQ–RCRA–2013–0209

COMMENTS OF ENVIRONMENTAL INTEGRITY PROJECT, SIERRA CLUB, EARTHJUSTICE, WATERKEEPER ALLIANCE, TENNESSEE CLEAN WATER NETWORK, WESTERN NORTH CAROLINA ALLIANCE, CLEAN AIR TASK FORCE, CHESAPEAKE CLIMATE ACTION NETWORK, CLEAN WATER ACTION, APPALACHIAN VOICES, ENVIRONMENTAL LAW & POLICY CENTER, ALLIANCE FOR THE GREAT LAKES, CONSERVATION LAW FOUNDATION, NATURAL RESOURCES DEFENSE COUNCIL, LABADIE ENVIRONMENTAL ORGANIZATION, AND VALLEY WATCH

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EXECUTIVE SUMMARY

Each day across the United States, coal-burning power plants dump millions of gallons of wastewater loaded with toxic pollutants like arsenic, boron, cadmium, chromium, lead, mercury, and selenium into our rivers, lakes, and streams. This pollution is discharged directly from the power plant; flows from old, unlined surface impoundments or "ponds" that many plants use to store toxic slurries of coal ash and smokestack scrubber sludge; and seeps from unlined ponds and landfills into ground and surface waters. EPA estimates that *at least 5.5 billion pounds* of pollution are released into the environment by coal-burning power plants every year.[1] Coal-burning power plants are responsible for at least 50 to 60 percent of the toxic pollutants discharged into waters of the U.S—more than the other nine top polluting industries *combined*.[2]

Coal combustion wastewaters contain a slew of toxic pollutants that can be harmful to humans and aquatic life in even small doses. Due to the bio-accumulative nature of many of these toxins, this pollution persists in the environment, and even short-term exposure can result in long-term damage to aquatic ecosystems. In short, coal plant water pollution has serious public health consequences and causes lasting harm to the environment. According to EPA, power plant pollution has caused over 160 water bodies not to meet state water quality standards, prompted government agencies to issue fish consumption advisories for 185 waters, and degraded 399 water bodies across the country that serve as public drinking water supplies.[3]

Despite the scope of this pollution problem, EPA is proposing to update the Effluent Limitation Guidelines ("ELGs") for this industry for only the first time since 1982. The existing ELGs for power plants are over thirty years old and fail to set any limits on toxic discharges in coal combustion wastewaters. Even in 1982, when EPA finalized its last revisions to the Steam Electric ELGs, the Agency acknowledged that future revisions would be necessary to address wastewaters from air pollution control systems, specifically FGD systems that are now being installed at coal-burning power plants in increasing numbers to comply with new Clean Air Act regulations.[4] In the absence of ELGs to control toxic pollution from coal-burning power plants, permitting agencies have largely failed to set limits on toxic pollution from power plants. The Environmental Integrity Project, Earthjustice, Sierra Club, Clean Water Action, and Waterkeeper Alliance released a report on July 23, 2013 that found that nearly 70 percent of power plant permits (188 out of 274) set *no limit* on how much toxic pollution these plants can discharge.[5]

EPA signed this proposed rule on April 19, 2013 as a condition of a consent decree to resolve litigation brought to compel the Agency to undertake overdue revisions of the Steam Electric ELGs.[6] EPA's proposal to set critically needed standards contains multiple options, including

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[1] EPA, Environmental Assessment for the Proposed Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category 3-14 (Apr. 2013), Docket No. EPA-HQ-OW-2009-0819-2260 [hereinafter EA].
[2] *Id.* at 3-13.
[3] http://water.epa.gov/scitech/wastetech/guide/steam-electric/proposed.cfm.
[4] 47 Fed. Reg. 52,290, 52,291 (Nov. 19, 1982).
[5] Environmental Integrity Project et al., Closing the Floodgates: How the Coal Industry is Poisoning Our Water and How We Can Stop It (July 23, 2013), at 7, *available at* http://www.environmentalintegrity.org/news_reports/documents/2013_07_23_ClosingTheFloodgates-Final.pdf.
[6] *See Defenders of Wildlife v. EPA*, No. 1:10-cv-01915-RWR (D.D.C. filed Nov. 8, 2010).

strong standards that would require the elimination of the majority of coal plant water pollution using technologies that are available and affordable. The strongest of these options—Option 5—would eliminate almost all toxic discharges, reducing pollution by more than 5 billion pounds a year. Option 4, the next strongest option, would eliminate new coal ash discharges and apply rigorous treatment requirements for FGD wastewater. By eliminating or significantly reducing toxic discharges from coal plants, a strong final rule would create hundreds of millions of dollars in benefits every year in the form of improved health and recreational opportunities for all Americans, in addition to the incalculable benefits of clean and healthy watersheds.[7] EPA estimates that ending toxic dumping from coal plants would cost less than one percent of annual revenue for most coal plants and at most about two pennies a day in expenses for ordinary Americans, if the utilities passed some of the cleanup costs on to consumers.[8]

Although Options 4 and 5 would eliminate most toxic water pollution from coal plants, the proposed rule does not designate them as "preferred" options. Instead, the EPA's proposal includes so-called "preferred" options that would do next to nothing to curb dangerous pollution from FGD wastewater discharges and would leave other major waste streams unregulated–including large amounts of toxic bottom ash waste.

It appears that the expressed preference for these weak options does not actually reflect the views of EPA. The White House's Office of Management and Budget ("OMB") took the highly unusual and improper step of writing new weak options into the draft rule prepared by the EPA's expert staff during the inter-agency review process established by executive order.[9] A redline of the rule, showing the original EPA version and OMB's version reveals the changes: OMB refused to let EPA choose more protective options as "preferred" regulatory paths and inserted weaker options instead.[10] The result is that EPA's original two preferred options — Options 3 and 4 —were replaced with four preferred options: Options 3a, 3b, 3, and 4a, three of which were created by OMB. OMB's elimination of Option 4 as a preferred option represented a position directly contrary to the views of EPA staff.[11] All of the preferred options that OMB inserted into the proposed rule are weaker than Option 4, meaning that OMB's intervention shifted the proposal away from the stringent controls that EPA has repeatedly recognized to be available and critical to achieving the Clean Water Act's goal of eliminating discharges.[12] If EPA finalizes any of these weaker options (or is forced to do so by OMB), it will fail to control billions of pounds of pollution, possibly for decades to come. It will also fail to exercise the duty—delegated to EPA alone by Congress—to develop standards based on its own expertise and judgment.

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[7] EPA, Benefit and Cost Analysis for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category at 12-2 (Apr. 2013), Docket No. EPA-HQ-OW-2009-0819-2238 [hereinafter BCA].

[8] *See* 78 Fed. Reg. 34,432, 34,501, table XI-9 (June 7, 2013) (noting that the average annual cost to ratepayers for the most stringent option is $6.46).

[9] EPA, Documentation of OMB Review Under Executive Order 12866 (June 2013), Docket No. EPA-HQ-LW-2009-0209 2237.

[10] *See generally id.*

[11] *See id.* at 137, 144, 213-214, 226-227; *see also* Environmental Integrity Project et al., Closing the Floodgates at 12-13.

[12] 78 Fed. Reg. at 34,458, 34,485-34,486.

Notwithstanding the weak options that EPA now puts forward as "preferred" options, EPA's underlying record for this rulemaking provides detailed analysis confirming that coal plants can shift away from leaking and unsafe impoundments to better and safer pollution controls, such as those incorporated into Options 4 and 5.[13] By transitioning to dry ash management systems and employing superior wastewater treatment technologies such as chemical precipitation, in combination with biological treatment or vapor compression, it is possible to reduce pollution from coal plants by billions of tons each year, even achieving zero liquid discharge.[14]

With regard to the specific determinations proposed by EPA in this rulemaking, these comments make the following key legal and technical points:

- **EPA Must Determine That Vapor Compression Evaporation is Best Available Technology ("BAT") to Treat Flue Gas Desulfurization ("FGD") Wastewater.** The leading technology for treatment of FGD wastewater—and the only one that will push the industry towards the national goal of zero liquid discharge as soon as possible—is chemical precipitation followed by mechanical evaporation (which EPA incorporated into Option 5). Mechanical evaporation is also the only technology evaluated by EPA that addresses all pollutants present in the FGD waste stream, including boron, bromides, and total dissolved solids, as EPA itself acknowledges. The record in this rulemaking establishes that mechanical evaporation is both technologically available and economically achievable, even as EPA has used inflated assumptions about the cost of mechanical evaporation for this proposed rule and fails to account for all of the health benefits of eliminating pollution from FGD wastewater, including bromide discharges that have been associated with the formation of dangerous disinfection byproducts in downstream public drinking water systems.

- **Chemical Precipitation Plus Biological Treatment is a Second-Best Alternative BAT for FGD Wastewater.** Chemical precipitation followed by biological treatment (which EPA incorporated into Options 4, 4a, 3, 3b (for units with wet-scrubbed capacity greater than 2000MW) and Option 2)) achieves substantial reductions in discharges of toxic mercury and arsenic—through the chemical precipitation process—and reductions in selenium and nitrate/nitrate levels through the biological treatment system. While it does not address bromides, boron, or TDS, it achieves the best removal, second to mechanical evaporation. If there is some legitimate reason for rejecting mechanical evaporation as BAT for FGD wastewater that EPA has yet to identify, then EPA must select biological treatment as BAT for FGD wastewater. Biological treatment is a well-established, affordable technology that is indisputably superior to chemical precipitation alone (which EPA incorporated into Option 1) as a treatment for FGD wastewaters.

- **EPA Must Reject Options that Allow BAT for FGD Wastewater to Be Determined Case-by-Case.** Options 3a and 3b (for plants with less than 2,000 MW wet-scrubbed capacity) would leave effluent limits to be set on a case-by-case basis. Not only is this

[13] *See, e.g.*, Technical Development Document for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category at 7-1-7-48 (Apr. 2013), Docket No. EPA-HQ-LW-2008-0819-2257, [hereinafter TDD].
[14] 78 Fed. Reg. at 34,485-34,486.

inconsistent with the Clean Water Act, it would be disastrous for water quality, wildlife, and public health based on the states' failing record at making BAT determinations. The Clean Water Act requires EPA to establish BAT for all categories of point sources. The Clean Water Act's provision for case-by-case BAT determinations is meant as a stop-gap measure where EPA has not yet addressed a particular pollutant discharged by an industry, not as an alternative to establishing ELGs where, as here, there are adequate data and available technology to set comprehensive BAT limits. Not only do states lack the resources, expertise, and political will to make meaningful BAT determinations on a permit-by-permit basis, but requiring states to do so is inefficient not only for the states themselves but also for permit applicants, local communities, environmental organizations, and other stakeholders who participate in the permitting process. Because under-resourced communities are less able to participate in a case-by-case permitting process, allowing BAT determinations to continue to be made in that process has profound environmental justice implications.

- **BAT-Based Limits Must Apply to All Coal Plants with Wet FGD Systems.** EPA's preferred Option 3b would set limits based on biological treatment only for units with a wet-scrubbed capacity of more than 2,000 MW. Option 3b would exclude from BAT-based limits all FGD wastewater generated in the country, except for the FGD waste stream at only 17 plants. Approximately 100 plants that currently operate FGD systems, as well as nearly every plant that adds a wet FGD system in the future, would have no limits on toxics metals in their FGD discharges. This threshold is not supported by the record on economic or technological grounds. Moreover, the rulemaking record is devoid of any basis for a 2,000 MW threshold, which appears to be based solely on cost savings to industry, and was improperly inserted by OMB during its review of the proposed rule.

- **Dry Ash Handling is BAT for Fly Ash Transport Water.** BAT for fly ash transport water is dry handling because eliminating the discharge of fly ash transport water is technologically and economically achievable. Fly ash transport water is one of the highest volumes of wastewater generated by power plants, and contains high concentrations of toxic pollutants. The average plant that generates fly ash transport water produces 2.4 million gallons of it each day. The electric industry discharged 81.1 billion gallons of fly ash transport water to surface waters in 2009. Given the volume of these toxic discharges, it is critical that EPA set BAT limits based on dry handling. Indeed, for over 30 years, Clean Water Act New Source Performance Standards have already required dry fly ash handling for new sources, and companies have both built and retrofit hundreds of units that meet this standard. It is long since time that EPA requires all existing facilities to do the same.

- **BAT for Bottom Ash Transport Water is Zero Discharge.** EPA should also set BAT limits based on zero discharge of bottom ash transport water for all units. The record demonstrates that all plants can install and afford zero discharge systems such as mechanical drag systems, remote mechanical drag systems, or vacuum and pressure systems. The cost of converting to zero discharge systems can be reasonably borne by the industry, even using EPA's cost estimates. However, EPA significantly overestimated costs by ignoring economies of scale, counting units that will likely retire or convert regardless of this rule, overestimating operating and maintenance costs, and using an inappropriately high annualization factor. Moreover, EPA failed to base its cost estimates on the cheapest options for achieving zero discharge – the vacuum and pressure systems that use no water at all, reduce operating and maintenance costs, and improve boiler efficiency. If the more accurate, lower cost estimates are used, the evidence that zero discharge systems are economically achievable is even more overwhelming.

- **Setting Less Stringent Bottom Ash Transport Water BAT Limits for Units Less than 400 MW Is Unsupported by the Record.** One of EPA's proposed options, Option 4a, would authorize 125 plants with a capacity equal to or less than 400 MW to continue to discharge bottom ash transport water after sending such water to leaking and unsafe impoundments where it receives minimal treatment. Option 4a would allow an additional 714 million pounds of pollutants of concern and 1.1 million pounds per year of toxic weighted pollutants to be discharged as compared with Option 4. Option 4a was not one of the options originally developed by EPA. Instead, it is the product of political interference by OMB during the regulatory review process. So it should come as no surprise that an option inserted at the last minute, after a highly politicized regulatory review process, conflicts with data in the record. The proposed 400 MW threshold is based on the unsupported assumption that the cost of zero discharge systems is disproportionately high for smaller units and will drive smaller units to retire early. The evidence in the record, however, shows that requiring all power plants to convert to dry bottom ash handling under Option 4 would cause only a negligible increase in retirements and that there is no meaningful relationship between the size of a unit and its relative cost of converting to dry bottom ash handling.

- **EPA Failed to Consider Chemical Precipitation Followed by Evaporation as BAT for Combustion Residual Leachate. At a Minimum, BAT for Combustion Residual Leachate is Chemical Precipitation Plus Biological Treatment for All Plants.** EPA must consider chemical precipitation followed by evaporation as BAT for combustion residual leachate. At a minimum, EPA should set BAT limits for combustion residual leachate based on chemical precipitation followed by biological treatment for all plants. The public health and environmental impacts from leachate are significant, and many of EPA's proven or potential coal ash damage cases were caused by leachate. Yet EPA underestimated loadings from combustion residual leachate by failing to account for leachate from surface impoundments; leaks and seeps from impoundments; and groundwater with a hydrogeological connection to surface waters. EPA should set BAT limits to prevent these discharges instead of maintaining the status quo as proposed under all of the Agency's preferred options.

- **EPA Must Select Option 5 for New Source Performance Standards.** The Clean Water Act requires EPA to set and revise New Source Performance Standards (NSPS) for new sources that "reflect[] the greatest degree of effluent reduction achievable" through Best Available Demonstrated Control Technology, a standard that is even more stringent than BAT. EPA improperly rejected Option 5 for new sources without applying the correct legal standard, which is whether the costs of Option 5 can be reasonably borne by the industry.

- **The Costs of Options 4 and 5 Can Be Reasonably Borne by the Industry.** When the correct legal standard is applied, EPA's own analysis establishes that the cost of both Options 4 and 5 can be reasonably borne by the industry, for both new and existing plants. EPA found, for all options in the rule, that "the entity-level compliance costs are low in comparison to the entity-level revenues; very few entities are likely to face economic impacts at any level."[15] EPA's decisions not to choose Options 4 and 5 appear to be influenced by cost-benefit analysis. The Clean Water Act and court decisions make clear that BAT limitations cannot be based on cost-benefit analysis. Congress precluded EPA from relying on cost-benefit analysis to develop BAT limitations because of concerns that the data on benefits will not be as extensive or robust as the data on costs, and therefore cost-benefit comparisons will inevitably skewed toward prioritizing costs. This rulemaking bears out Congress's concerns, since EPA's cost-benefit analysis systematically overestimates costs and underestimates benefits.

- **Best Management Practices ("BMPs") for Construction, Operation and Maintenance of Coal Ash Surface Impoundments Must Establish Timely and Enforceable Minimum Standards.** EPA is considering establishing BMPs that would apply to surface impoundments to prevent uncontrolled discharges from impoundment failures. Specific standards for design, inspection and corrective action are set forth in both the Mine Safety and Health Administration regulations and in EPA's proposed coal combustion residuals rule modeled after those regulations. EPA should establish BMPs that require adherence to these specific standards, and these standards should be made enforceable in permits, with detailed inspection and corrective action requirements, to ensure consistent and effective controls on all coal ash impoundments nationwide. If EPA fails to require specific BMPs in permits, with clear reporting and corrective action requirements, then states will continue to write permits without enforceable structural integrity standards.

- **EPA Should Establish Specific and Enforceable BMPs for Closure of Coal Ash Impoundments.** The billions of tons of coal combustion waste currently disposed in surface impoundments have the potential to significantly harm both surface water and groundwater with hydrogeological connections to surface water. It is essential that EPA establish BMPs to ensure coal ash impoundments are safely closed to minimize pollutant discharge to such waters. In order to ensure that coal ash impoundments nationwide are subject to adequate and consistent conditions for safe closure, EPA must require specific design, maintenance and remediation criteria similar to the closure requirements for coal ash surface impoundments proposed under the Resource Conservation and Recovery Act ("RCRA"). Where coal ash is left in place, EPA must require closure plans with minimum safeguards including provisions for major slope stability, groundwater monitoring, cap-and-cover requirements, provisions to preclude the probability of future impoundment of water, and post-closure care.

[15] RIA at 4-9.

- **The Clean Water Act Does Not Support EPA'S Proposed Voluntary Incentives Program.** EPA has proposed establishing, as part of the BAT for existing sources, voluntary incentive programs that provide more time for plants to implement the proposed BAT requirements if they adopt additional process changes and controls that provide environmental protections beyond those achieved by the preferred options for this proposed rule. These programs, however, are ill-conceived, will fail to achieve their stated objectives, contain no deadline for compliance with their requirements, and would allow power plants to substantially delay compliance with BAT requirements in violation of statutory deadlines. Instead of encouraging utilities to execute technologies that would not otherwise be required, EPA's proposed Tier 1 program makes an end run around conventional solid waste closure requirements that the Agency should mandate in this rulemaking or pursuant to RCRA). EPA's proposed Tier 2 program does not address leaking impoundments, groundwater discharges with a hydrogeological connection with surface waters, and legacy wastewaters, and it places the burden on permitting agencies to develop individual interim discharge limits where they have repeatedly failed to do so in the past.

- **Industry Must Comply with the Final ELGs No Later than Three Years Before the Date the Rule Is Finalized.** The plain language of the Clean Water Act requires that compliance with revised ELGs must occur within three years of promulgation of the final rule. EPA's proposed compliance deadline turns that standard on its head, allowing for three years of delay before any compliance is required, and setting no hard deadline for compliance for standards implemented through state-issued permits. State permitting agencies routinely fail to renew permits for power plants in a timely manner even though the Clean Water Act requires discharge permits to be renewed every five years. Moreover, the record does not demonstrate that facilities cannot comply with new BAT requirements within three years of the effective date of the rule. EPA must state in the final rule that compliance is required with the new BAT requirements "as soon as possible, but no later than three years from the effective date of the final rule." The Clean Water Act mandates cleanup and there is no excuse for further delay.

- **The Clean Water Act Obligates EPA to Set BAT for Discharges of Existing Wastes.** Under all proposed options, for all waste streams, the new BAT requirements, along with Pretreatment Standards for Existing Sources ("PSES"), would apply only to wastewater generated after the rule's compliance deadline. The proposed rule thus would exempt existing, "legacy" wastewater that is stored in impoundments but discharged after the rule goes into effect. Moreover, the proposal goes one step further, purporting to determine that impoundments are BAT for this wastewater. EPA's determination is contradicted by the record, which establishes that several treatment systems are technologically available and economically achievable for dramatically reducing the toxicity of existing wastes, whether stored separately or co-mingled in impoundments. EPA must evaluate and determine BAT for each legacy wastewater stream, since the Clean Water Act requires EPA to establish effluent limitations that reduce or eliminate discharges of pollutants without regard to when those pollutants were first generated.

- **EPA's Integration of the ELG and CCR Rules Must Consider the Nature and Scope of the Risks Posed by Coal Combustion Residuals to Human Health and the Environment.** EPA's efforts to "align" the proposed ELG and CCR rules fails to consider the distinct and significant risks posed by each pollution source. The ELG rule addresses ongoing permitted discharges to surface waters, while the CCR rule addresses the broader threats posed by coal ash disposal, including risks of catastrophic impoundment collapse, seeps and leaks from these impoundments both to surface water and to groundwater, leaking coal ash landfills, landfill siting, cleanup requirements, and fugitive dust. Use of data from the 2010 ELG surveys can enhance understanding of the risks posed by coal ash, but there is also a danger that the data will be misinterpreted and misused. In fact, EPA's suggested use of several data sets is likely to underestimate significantly the risk to human health and the environment from improperly managed coal ash. Further, EPA appears in this proposed rule and in the coal ash Notice of Data Availability that preceded it, to be ignoring ELG survey data that show distinctly increased risk from coal ash. The desired "alignment" of the rules must not take precedence over the goal of protecting health and the environment from all risks posed by power plant wastes.

- **EPA Must Revise its Environmental Justice Analysis to Evaluate Impacts to Communities Surrounding Power Plants and to Consider the Impacts of its Weakest Options.** EPA failed to conduct the required inquiry into whether its regulatory options have a disproportionately high and adverse health or environmental impact on communities of color and low-income populations. The Agency's cursory inquiry focused on only one adverse impact of pollution discharges (consumption of contaminated fish) and failed entirely to evaluate the health and environmental harms suffered by communities proximate to the source of pollution. The abbreviated inquiry does not satisfy Executive Order 12989 nor is it consistent with the environmental justice assessment conducted by the Agency for its 2010 proposed CCR rule on identical pollution sources. EPA's indefensibly narrow environmental justice analysis represents substantial noncompliance with the Executive Order that must be rectified.

- **The ELG Rule Does Not Eliminate the Need for Stringent Coal Ash Disposal Rules under RCRA.** While Options 4 and 5 of the ELG rule are critical steps to controlling the liquid discharges from coal-burning power plants, EPA must not stop there— the Agency must proceed to finalize a coal ash rule as soon as possible. The most stringent options in the proposed ELG rule eliminate the discharge of billions of gallons of toxic wastewater to our rivers and streams each year, as well eliminate the disposal of liquid waste in more than 1,000 largely unlined or inadequately-lined ash and sludge impoundments. While these are essential and long overdue steps, the rule does not begin to address many additional health and environmental threats posed by coal ash. Specifically, the ELG rule does not address safe closure of the thousand leaking and potentially unstable coal ash impoundments nor does it address monitoring and cleanup of contaminated groundwater, control of toxic dust, siting and construction of engineered landfills or provision of financial assurance for toxic spills and dump closures. Federally enforceable minimum standards under RCRA are needed to complement the strongest ELG option, and together they can address the toxic pollution from the hundreds of polluting coal-burning power plants.

After decades of delay, the Clean Water Act demands that EPA set strong, national standards to curb dangerous coal plant water pollution and protect public health and our waters. Under the terms of the consent decree, EPA must finalize the rule no later than May 22, 2014.

I. BACKGROUND

A. COAL-BURNING POWER PLANTS ARE THE LARGEST INDUSTRIAL SOURCE OF TOXIC WATER POLLUTION BASED ON TOXICITY AND VOLUME.

Each day across the United States, coal-burning power plants dump millions of gallons of wastewater loaded with toxic pollutants like arsenic, boron, cadmium, chromium, lead, mercury, and selenium into our rivers, lakes, and streams. This pollution is discharged directly from the power plant; flows from old, unlined surface impoundments or "ponds" that many plants use to store toxic slurries of coal ash and smokestack scrubber sludge; and seeps from unlined ponds and landfills into ground and surface waters. EPA estimates that *at least 5.5 billion pounds* of pollution are released into the environment by coal-burning power plants every year.[16]

Coal plants are the largest source of toxic water pollution in the United States, dumping more toxics (based on toxic weighted pound equivalent ("TWPE")) into our waters than the other top nine polluting industries combined.[17]

Table 1 – Pollutant Loadings for Top 10 Point Source Categories[18]

Point Source Category	Total TWPE (lb-eq/yr)
Steam Electric Industry	8,320,000
Pulp, Paper and Paperboard	1,030,000
Petroleum Refining	1,030,000
Nonferrous Metals Manufacturing	994,000
Fertilizer Manufacturing	826,000
Organic Chemicals, Plastics, Synthetic Fibers	649,000
Ore Mining and Dressing	448,000
Inorganic Chemicals Manufacturing	299,000
Waste Combustors	254,000
Textile Mills	250,000

This dangerous pollution, including at least 1.79 billion pounds (4.8 million TWPE) of metals per year alone,[19] makes its way into water bodies across the country; fish and other aquatic life; and our bodies, through fish and water consumption, swimming, boating, and other activities.[20] These metals, which include arsenic, boron, cadmium, chromium, lead, mercury, selenium, and other toxics, can be hazardous to humans or aquatic life in very small doses (measured in parts per billion) because they do not degrade over time and bio-accumulate, meaning they increase in concentration as they are passed up the food chain. In addition to metals pollution, power plants

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[16] EA at 3-13 tbl. 3-2.
[17] *See id.* at 3-14 (total toxic-weighted pollution from steam electric power plants is 8.3 million TWPE; total pollution from remaining top ten industries is 5.78 million TWPE).
[18] *Id.* at 3-14 tbl. 3-3.
[19] *Id.* at 3-13 tbl. 3-2.
[20] *See id.* at 5-7 – 5-17.

discharge nutrients like nitrogen and phosphorous that can choke watersheds and wreak havoc on treasured ecosystems like the Great Lakes and Chesapeake Bay.[21]

The EPA estimates that, each day, a single coal-burning power plant discharges approximately 4.2 million gallons of fly and bottom ash transport water.[22] In addition, the increasing use[23] of flue-gas desulfurization systems and other pollution controls to prevent toxics from leaving smokestacks generates new waste streams[24] and concentrates this pollution[25] in a wet sludge that often ends up in surface impoundments.[26] These surface impoundments, as well as landfills, are often unlined or poorly lined, which results in pollution discharges to both ground and surface waters.[27] In some cases, coal ash landfills or wet impoundments cover hundreds of acres, fill in local wetlands, and turn streams into drainage ditches for toxic waste that either leaks or is discharged from these sites.[28]

B. THE TOXIC SUBSTANCES IN COAL-BURNING POWER PLANT WASTEWATERS POSE A RISK TO PUBLIC HEALTH AND THE ENVIRONMENT.

EPA has recognized serious adverse impacts from coal plant water pollution across the country:

> [E]xposure to combustion wastewater has been associated with fish kills, reductions in growth and survival of aquatic organisms, behavioral and physiological effects in wildlife and aquatic organisms, and changes to the local habitat. As well as directly affecting aquatic ecology and local wildlife, combustion wastewater has had other environmental impacts such as altering local habitats, contaminating drinking water wells, and contributing to fish advisories.[29]

Coal combustion wastewaters contain a slew of toxic pollutants that can be harmful to humans and aquatic life in small doses. Due to the bio-accumulative nature of many of the pollutants, this pollution persists in the environment, and even short-term exposure can result in long-term damage to aquatic ecosystems. In short, coal plant water pollution has serious public health consequences and causes lasting harm to the environment.

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[21] *Id.* at 3-13, Table 3-2, 3-20 – 3-24.
[22] TDD at 6-10.
[23] EPA estimates a 900% increase in wet scrubbed capacity since 1982. TDD at 4-33.
[24] 78 Fed. Reg. 34,432, 34,449 (June 7, 2013).
[25] Laura Ruhl, Avner Vengosh et al., The Impact of Coal Combustion Residue Effluent on Water Resources: A North Carolina Example, Envtl. Science & Technology (Sept. 30, 2012), *available at* http://sites.nicholas.duke.edu/avnervengosh/files/2011/08/es303263x1.pdf.
[26] TDD at 7-3 (noting that at least 44% dispose of FGD wastewater in surface impoundments).
[27] *See* responses to Steam Electric Questionnaire, Part A, Power Plant Operations, Question A4-1 and Part D, Pond/Impoundment Systems, Questions D4-4.
[28] *See, e.g.*, EA at 3-34-3-41, A-11-A-39.
[29] EA at 5-1 (internal citations omitted).

1. *Coal combustion wastewaters contain toxic pollutants that can harm humans and the environment.*

Coal ash transport water, FGD wastewater, and combustion residual leachate contain heavy metals and other pollution that can harm humans and the environment. For example, coal-burning power plant wastewaters contain:

Arsenic

Arsenic is a potent poison. Power plants discharge at least 79,200 pounds (320,000 TWPE) of arsenic every year.[30] According to the EPA, arsenic is "frequently observed at elevated concentrations" near coal waste sites, where it has been found in groundwater, and it can also build up, or "bio-accumulate," in ecosystems affected by these discharges.[31] Arsenic causes cancer, including lung cancer, skin tumors and internal organ tumors,[32] and is also connected to heart problems, nervous system disorders, and intense stomach pain.[33] EPA estimates that nearly 140,000 people per year experience increased cancer risk due to arsenic in fish from coal plants.[34] Arsenic in drinking water is also linked to miscarriages, stillbirths, and infants with low birth weights.[35]

Mercury

As EPA explains, even though mercury concentrations in coal plant waste can be relatively low, "mercury is a highly toxic compound that represents an environmental and human health risk even in small concentrations," and the conditions at the bottom of coal waste impoundments are particularly likely to convert mercury into its most toxic forms.[36] Mercury is a bio-accumulating poison that impairs brain development in children and causes nervous system and kidney damage in adults.[37] A fraction of a teaspoon of mercury can contaminate a 25-acre lake,[38] and coal plants dump 2,820 pounds (330,000 TWPE) into our waters every year.[39] Mercury also accumulates in fish, making them unsafe to eat.[40] EPA estimates that almost 2,000 children per year are born with lower IQs because of mercury in fish that their mothers have eaten.[41]

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[30] EA at 3-13.

[31] U.S. Envtl. Prot. Agency, Steam Electric Power Generating Point Source Category: Final Detailed Study Report (EPA-821-R-09-008) 6-5 (2009), Docket No. EPA-HQ-OW-2009-0819-0387 [hereinafter Detailed Study Report], *available at* http://water.epa.gov/scitech/wastetech/guide/steam-electric/upload/Steam-Electric_Detailed-Study-Report_2009.pdf.

[32] Id.

[33] *Id.* at 20-22.

[34] BCA at 3-6.

[35] Agency for Toxic Substances and Disease Registry, Toxicological Profile for Arsenic 18 (2007), *available at* http://www.atsdr.cdc.gov/toxprofiles/tp2.pdf.

[36] Detailed Study Report at 6-5.

[37] Agency for Toxic Substances and Disease Registry, Public Health Statement for Mercury §§ 1.5-1.6, *available at* http://www.atsdr.cdc.gov/ToxProfiles/tp46-cl-b.pdf.

[38] Union of Concerned Scientists, Environmental Impacts of Coal Power: Air Pollution, http://www.ucsusa.org/clean_energy/coalvswind/c02c.html (last visited Sept. 13, 2013).

[39] EA at 3-13.

[40] Agency for Toxic Substances and Disease Registry, Public Health Statement for Mercury § 1.2, *available at* http://www.atsdr.cdc.gov/ToxProfiles/tp46-cl-b.pdf.

[41] BCA at 3-13.

Selenium

Coal power plants discharge 225,000 pounds (252,000 TWPE) of selenium each year,[42] which can wreak havoc in aquatic ecosystems.[43] "In humans, short-term exposure at levels above the MCL can cause hair and fingernail changes, damage to the peripheral nervous system, and fatigue and irritability. Long-term exposure can damage the kidney, liver, and nervous and circulatory systems."[44] Selenium is acutely poisonous to fish and other aquatic life in even small doses; concentrations below 3 – 8 µg/L can kill fish, and lower concentrations can leave fish deformed or sterile.[45] Selenium also bio-accumulates and interferes with fish reproduction, meaning that it can permanently destroy wildlife populations in lakes and rivers as it works its way through the ecosystem over a period of years.[46] "EPA has documented numerous damage cases where selenium in combustion wastewater discharges resulted in fish consumption advisories being issued for surface waters and selenium MCLs being exceeded in ground water . . . ."[47]

Lead

Lead is a highly toxic poison that "can cause serious damage to the brain, kidneys, nervous system, and red blood cells, especially in children.[48] EPA estimates that nearly 13,000 children under the age of seven each year have reduced IQs because of lead in fish they eat.[49] Coal plants dump 64,400 pounds (144,000 TWPE) of lead into the water each year.[50] Once lead enters the river ecosystem, it can enter the food chain and bio-accumulate, leading to serious harm to wildlife, and placing our children in harm's way.[51] "Leachate has caused ground water to exceed state drinking water standards for lead."[52]

Cadmium

Cadmium is another bio-accumulating and very toxic pollutant.[53] Power plants send 31,900 pounds (738,000 TWPE) each year into our water.[54] ATSDR warns that drinking water with elevated cadmium levels can cause kidney damage, fragile bones, vomiting and diarrhea, and sometimes death.[55] Cadmium also likely causes cancer.[56] Fish exposed to excess cadmium become deformed.[57]

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[42] EA at 3-13.
[43] *See, e.g.*, Detailed Study Report at 6-4; EA at 3-4 tbl. 3-1.
[44] EA at 3-4.
[45] *See, e.g.*, Detailed Study Report at 6-4; EA at 3-4 tbl. 3-1.
[46] *See, e.g.*, EA at 3-5-3-6; 3-24-3-26.
[47] *Id.* at 3-6.
[48] *Id.* at 3-8.
[49] BCA at 3-10.
[50] EA at 3-13.
[51] *Id.* at 3-8.
[52] *Id.* at 3-4 tbl. 3-1.
[53] *Id.* at 3-7.
[54] *Id.* at 3-13.
[55] Agency for Toxic Substances and Disease Registry, Public Health statement for Cadmium 5 (2012), *available at* http://www.atsdr.cdc.gov/ToxProfiles/tp5-c1-b.pdf.

Boron

Boron is rare in unpolluted water, meaning that even small concentrations can be toxic to wildlife not usually exposed to this pollutant.[58] Coal plants discharge more than 54 million pounds of boron annually, converting a rare contaminant into a common-place pollutant downstream of their discharge points.[59] Ingestion of large amounts of boron can result in damage to the stomach, intestines, liver, kidney, and brain.[60] Low birth weights, birth defects, and developmental delays have occurred in newborn animals whose mothers were orally exposed to high doses of boron (as boric acid) during pregnancy.[61] Boron's effect on people in low doses is unclear, but some studies suggest that it can cause nausea, vomiting, and diarrhea.[62]

Bromides

Coal plant waste contains bromide salts, which are very hard to remove short of evaporating wastewater to crystallize out these pollutants.[63] Bromides interact with wastewater treatment systems at public drinking water intakes to form disinfection byproducts, including a class of chemicals called trihalomethanes, which are linked to bladder cancer.[64]

Nitrogen and Phosphorus

Nitrogen and phosphorous are nutrients that are beneficial in small quantities, but can readily overpower ecosystems in larger quantities, converting clear waters into algae-choked sumps.[65] Because coal plants dump more than 30 million pounds of nitrogen and 682,000 pounds of phosphorus annually, they are a significant point source contributor to harmful nutrient loadings in the Chesapeake Bay and other watersheds.[66]

TDS

Total dissolved solids is a category of salts such as chlorides, bromides, calcium, magnesium, and other common dissolved metals. Elevated levels of TDS can stress aquatic organisms with potential toxic effects, and also have adverse impacts on agriculture and wetlands. The EPA has set secondary maximum contaminant levels for TDS and some of its constituents in drinking water, because TDS can lead to unacceptable odors and tastes in drinking water. TDS is also

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[56] Id.
[57] EA at 3-8.
[58] *Id.* at 3-8-3-9.
[59] *Id.* at 3-13.
[60] Agency for Toxic Substances and Disease Registry, ToxFAQs for Boron (2010), *available at http://www.atsdr.cdc.gov/toxfaqs/tf.asp?id=452&tid=80.*
[61] *Id.*
[62] *Id.* at 3-9.
[63] *See* 78 Fed. Reg. at 34,477 (June 7, 2013).
[64] *Id.* at 34,505.
[65] *See* EA at 3-9-3-10.
[66] *Id.* at 3-10.

known to contribute to corrosion, staining, scaling, and sedimentation, which can have a major impact on water distribution system infrastructure, and the appliances of end-users.

The EPA has identified many other dangerous substances in coal plant wastewater, including chromium, molybdenum, and thallium, all of which can cause adverse health impacts and harm to the environment.[67]

2. *Coal plant water pollution is persistent and widespread.*

Coal-burning power plants are usually located on or near a waterway because they rely on huge volumes of water to operate. A 2012 report found that coal-burning power plants require an average of over 16,000 gallons of water withdrawn and over 690 gallons consumed per megawatt-hour.[68] The United States Geological Survey found in its last major water use survey that power plant water withdrawals accounted for 49% of total water used in the United States,[69] much of which gets discharged back into hundreds of rivers, lakes, and streams all across the United States, many of which are popular recreational spots for boating, swimming, and fishing and are drinking water sources for nearby communities.

The scope of coal plant water pollution is staggering. According to EPA, two-thirds of the waterways receiving coal plant waste have reduced water quality as a direct result of that pollution.[70] Nearly half of those waterways (49 percent) have water quality worse than the EPA's National Recommended Water Quality Criteria, and a fifth of them violate standards for drinking water.[71] Seventy-eight power plants discharge directly into a water body that has been formally listed as having water quality impaired by a pollutant in coal waste, with mercury being the most common cause of impairment.[72]

A recent survey of waters affected by nine power plants demonstrates the pervasiveness of these dangerous discharges. Based on intensive water sampling in North Carolina, researchers from Duke University found contamination all across the state.[73] Researchers found concentrations of arsenic in discharges from the Asheville and Riverbend plants at levels four to nine times greater than the EPA's drinking water standards.[74] Discharges from the Mayo and Asheville plants had selenium concentrations above EPA's recommended chronic exposure criterion for aquatic life—up to 17 times greater in one instance.[75] The Asheville plant discharges also exceeded human

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[67] *Id.*at 3-13 tbl. 3-2; 3-4 tbl. 3-1.
[68] Wendy Wilson, Travis Leipzig & Bevan Griffiths-Sattenspiel, *Burning Our Rivers: The Water Footprint of Electricity*, 10, 13-14 (River Network 2012), *available at* http://www.rivernetwork.org/sites/default/files/BurningOurRivers_0.pdf.
[69] Kenny, J.F., Barber, N.L., Hutson, S.S., Linsey, K.S., Lovelace, J.K., and Maupin, M.A., 2009, Estimated use of water in the United States in 2005: U.S. Geological Survey Circular 1344, *available at* http://pubs.er.usgs.gov/publication/cir1344.
[70] EA at 5-8.
[71] *Id.* at 5-9.
[72] *Id.* at 6-36.
[73] Laura Ruhl, Avner Vengosh et al., The Impact of Coal Combustion Residue Effluent on Water Resources: A North Carolina Example, Envtl. Science & Technology (Sept. 30, 2012), *available at* http://sites.nicholas.duke.edu/avnervengosh/files/2011/08/es303263x1.pdf.
[74] *Id.* at 12228.
[75] *Id.*

and aquatic life standards for antimony, cadmium, and thallium.[76] The lakes and rivers receiving this waste, predictably, showed elevated levels of toxics, including arsenic and selenium, even though they are large bodies of water.[77] Fish in Mayo Lake, which receives discharges from the Mayo plant, are deformed in ways that indicate selenium poisoning.[78]

This pollution persists in the environment due to the bio-accumulative nature of arsenic, selenium, and other coal combustion pollution, posing a lasting threat to both humans and the environment.[79] For example, the Duke researchers discovered that even in large lakes, arsenic can accumulate in sediment on the lake bottom and then erupt from the lake bottom as water warms and stratifies in the summer, emerging back into the lake during the same summer days when many people are likely to be out fishing and swimming.[80] In addition, even short-term exposure to coal combustion wastewater can have lasting impacts. In Martin Lake in Texas, "ecological effects persisted for at least eight years following eight months of fly ash discharges into the lake."[81]

3. *Coal plant water pollution threatens public health.*

EPA estimates that 11,200 miles of rivers do not meet recommended water quality standards for human health as a result of coal plant water pollution.[82] Nearly 15,000 miles of river do not meet recommended water quality standards for recreation.[83] In many of these waterways, fish are not safe to eat. For example, mercury in fish poses a threat to people eating fish caught for food in seventy-three percent of immediate receiving waters.[84] All 50 states currently have fish advisories in place, warning women of childbearing age, children, and other populations vulnerable to toxics, to strictly curtail or eliminate freshwater fish caught in those states from their diets.[85] In addition, nearly 40% of power plants are located within 5 miles of a drinking water intake, and 85% of plants are located within 5 miles of a public well.[86]

The EPA estimates that nearly 140,000 people per year experience increased cancer risk due to arsenic in fish from coal plants; nearly 13,000 children under the age of seven each year have reduced IQs because of lead in fish they eat; and almost 2,000 children are born with lower IQs because of mercury in fish their mothers have eaten.[87] "[F]ish thallium concentrations pose a non-cancer threat to humans in approximately 40 percent of immediate receiving waters. . . . [H]umans who consume thallium-contaminated fish inhabiting these waters are more likely to develop neurological symptoms (e.g., weakness, sleep disorders, muscular problems), alopecia

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[76] *Id.*
[77] *Id.* at 12230.
[78] *Id.* at 12231.
[79] *Id.*
[80] *Id.*
[81] EA at 3-25.
[82] *Id.* at 6-46 tbl. 6-15.
[83] *Id.*
[84] *Id.* at 5-16-5-17.
[85] EPA, 2010 Biennial National Listing of Fish Advisories, EPA-820-F-11-014, at 5 (Nov. 2011), *available at* http://water.epa.gov/scitech/swguidance/fishshellfish/fishadvisories/upload/technical_factsheet_2010.pdf.
[86] *Id.* at 3-33.
[87] BCA at 3-6 – 3-14.

(i.e., loss of hair from the head and body), and gastrointestinal effects (e.g., diarrhea and vomiting)."[88]

The nationwide poisoning of fish is particularly unjust for communities that depend heavily on fish for food. According to the National Environmental Justice Advisory Council, families in many communities of color, including African-Americans and Native peoples, rely on fishing to supply basic nutritional needs.[89] As the Council wrote, "[p]ut simply, communities of color, low-income communities, tribes, and other indigenous peoples *depend* on healthy aquatic ecosystems and the fish, aquatic plants, and wildlife that these ecosystems support."[90] Fishing provides an inexpensive, reliable, and healthful food source, but when fish are contaminated, reliance on fishing for food makes these communities far more vulnerable to water pollution and contaminated fish than the general population.[91]

4. Coal plant water pollution causes harm to the environment.

In addition to the serious public health consequences associated with coal plant pollution, there is no question that harm to fish and other wildlife from such pollution is widespread, serious, and persistent. Scientists have documented coal pollutants, like selenium and arsenic, building up to "very high concentrations" in fish and wildlife exposed to coal combustion wastewaters, and those accumulating toxics can ultimately deform or kill animals.[92] EPA identified 132 case studies and damage cases that document surface water impacts and 123 case studies and damage cases that document groundwater impacts from exposure to coal combustion wastewaters.[93] "Surface water impacts include damage to fish populations (i.e., physiological and morphological abnormalities and various behavioral, reproductive, and developmental effects), decreased diversity in insect populations, and decline of aquatic macroinvertebrate population."[94] One survey focusing on reported fish and wildlife damage caused by coal waste discharges shows that 22 of these incidents alone caused damage of more than $2.3 billion.[95]

For example, in North Carolina, Belews Lake, a popular fishing and recreation spot, was contaminated by just over a decade of coal waste dumping.[96] Just ten years of discharges were enough to eliminate 18 of the 20 fish species in the lake and to leave dangerous levels of contamination in fish and birds more than ten years later.[97] In Hyco Reservoir, also in North

[88] EA at 5-16.
[89] National Environmental Justice Advisory Council, Fish Consumption and Environmental Justice iii-iv (2002), *available at* http://www.epa.gov/environmentaljustice/resources/publications/nejac/fish-consump-report_1102.pdf.
[90] *Id.* at 2.
[91] *Id.*
[92] Christopher Rowe et al., Ecotoxicological Implications of Aquatic Disposal of Coal Combustion Residues in the United States: A Review, 80 Env. Monitoring and Assessment 207, 215, 231-236 (2002).
[93] EA at 3-34. In many cases, contaminated groundwater adversely impacts surface waters with a hydrogeologic connection. *See* EA at A-29-A-39 (documenting 30 of 67 cases where surface water damage was caused by contaminated groundwater).
[94] *See id.* at 3-34.
[95] A. Dennis Lemly, Wildlife and the Coal Waste Policy Debate: Proposed Rules for Coal Waste Disposal Ignore Lessons from 45 Years of Wildlife Poisoning, Env. Sci. Tech. (2012).
[96] Dennis Lemly, Symptoms and implications of selenium toxicity in fish: the Belews Lake case example, 57 Aquatic Toxicology 39 (2002).
[97] *Id.*

Carolina, coal plant dumping led to an $864 million fish kill that left selenium levels in blue gill 1,000 times greater than ordinary water concentrations.[98] In Texas, at Martin Creek Reservoir, a coal plant discharged fly ash wastewater for just eight months; within two years, 90 percent of plankton-eating fish in the lake had died, and largemouth bass and bluegill could no longer reproduce.[99] Even a few years later, fish in the lake were riddled with dead or dying tissue in their internal organs.[100]

In addition, the millions of pounds of nutrient pollution that power plants discharge each year can "cause oxygen-consuming algae blooms and create 'dead zones' where fish and shellfish cannot survive, block sunlight that is needed for underwater grasses, and smother aquatic life on the bottom of [waterways].[101] For example, EPA identified 20 power plants that discharge "2.2 million pounds of nitrogen and 60,000 pounds of phosphorous" to the Chesapeake Bay watershed each year.[102] These plants contribute 30% of all nitrogen loadings to this struggling watershed, which is among the most ecologically and economically important estuaries in the country.[103] For all these reasons, coal-burning power plant operators' uncontrolled dumping of toxic waste into our rivers, lakes, and streams has serious consequences for public health and the environment.

C. DUE TO DECADES OF REGULATORY DELAY AND STATE FAILURE TO CONTROL TOXIC DISCHARGES IN THE ABSENCE OF FEDERAL STANDARDS, COAL-BURNING POWER PLANT POLLUTION HAS REMAINED LARGELY UNCHECKED FOR MORE THAN THIRTY YEARS.

While coal-burning power plants are the nation's largest dischargers of toxic pollutants, EPA never proposed to regulate the vast majority of pollutants in coal plant wastewaters[104] until now. The existing ELGs for power plants are over thirty years old and fail to set any limits on toxic discharges in coal combustion wastewaters.

EPA has long recognized this regulatory gap, but the Agency has neglected to revise the ELGs for power plants until now. Even in 1982, when EPA finalized its last revisions to the Steam Electric ELGs, the Agency acknowledged that future revisions would be necessary to address wastewaters from air pollution control systems, specifically FGD systems that are now being installed at coal-burning power plants in increasing numbers to comply with new Clean Air Act regulations.[105] In 1994, and again in 1996 and 1998, EPA acknowledged that the Steam Electric category was a candidate for future rulemaking and indicated that a preliminary study of discharges from this category was necessary.[106] In 2003, EPA identified the Steam Electric

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98 Rowe et al, *supra* note 77, at 231.
99 Lemly, *supra* note 80.
100 Rowe et al, *supra* note 77, at 241.
101 EA at 3-13; 3-19.
102 *Id.* at 3-20.
103 *Id.* at 3-20.
104 *See, e.g.*, 47 Fed. Reg. 52,290, 52,291 (Nov. 19, 1982) ("reserving effluent limitations for four types of wastewaters for future rulemaking" including "[f]lue gas desulfurization waters").
105 47 Fed. Reg. at 52,291.
106 *See* 59 Fed. Reg. 25,859, 25,864, 25, 867 (May 18, 1994); 61 Fed. Reg. 35,042, 35,047, 35,049, 35,053 (July 3, 1996); 63 Fed. Reg. 29,203, 29,208 (May 28, 1998).

category as having a "relatively high estimate of potential hazard or risk" and stated that EPA would "continue investigating pollutant discharges" from this category.[107]

In 2006 and 2007, EPA acknowledged that the Steam Electric category ranked second in overall discharges of toxic and nonconventional pollutants and anticipated that this category would produce even higher amounts of selenium and other metals in power plant discharges due to an increase in the use of air pollution controls.[108] In 2008, EPA affirmed its previous findings and further concluded that the toxicity of coal plant discharges was primarily driven by metals associated with coal ash handling and scrubber waste.[109] However, even as EPA acknowledged the risks posed by coal combustion wastewaters year after year, it never revised the regulations to reduce these hazardous discharges.

In the absence of ELGs to control toxic pollution from coal-burning power plants, permitting agencies have largely failed to set limits on these discharges. Where EPA fails to set ELGs for a particular point source category or pollutants, permitting agencies are required by the Clean Water Act to set limits in discharge permits for individual plants that reflect the best available treatment technology and protect water quality.[110] In addition, if discharges may cause or contribute to exceedances of water quality criteria, the permitting agency must set more stringent water quality-based limits.[111] Despite the mandate of the Clean Water Act, permitting agencies routinely fail to set limits on toxic pollution from power plants.

The Environmental Integrity Project, Earthjustice, Sierra Club, Clean Water Action, and Waterkeeper Alliance released a report on July 23, 2013 that surveyed EPA's Enforcement and Compliance History Online (ECHO) database and power plant permits to evaluate agency compliance with the Clean Water Act at coal-burning power plants.[112] Specifically, the groups reviewed the ECHO database discharge permits to determine how many plants that discharge coal ash or scrubber waste are required to comply with effluent limits and/or monitoring requirements for six representative metals—arsenic, boron, cadmium, lead, mercury, and selenium.[113] Our analysis shows that nearly 70 percent of power plant permits (188 out of 274) set *no limit* on how much of this dangerous pollution these plants can discharge.[114] Only 86 of 274 plants were required to comply with at least one limit on arsenic, boron, cadmium, lead, mercury, or selenium.[115] These permit limits vary by stringency and by completeness. Very few plants, for example, have protective limits for all six metals; most have limits for only a subset of these poisons.[116] For example, far more plants have limits for selenium than they do for arsenic, cadmium, boron, or lead.[117]

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[107] 68 Fed. Reg. 75,515, 75,528 (Dec. 31, 2003).
[108] 71 Fed. Reg. 76,644, 76,653 (Dec. 21, 2006); 72 Fed. Reg. 61,335, 61,342 (Oct. 30, 2007).
[109] 73 Fed. Reg. 53,218, 53,225–53,226 (Sept. 15, 2008).
[110] 33 U.S.C. § 1314(b); 40 C.F.R. §§ 122.44(a)(1), 123.25, 125.3.
[111] 33 U.S.C. § 1312(a); 40 C.F.R. § 122.44(d)(1)(i) (2011).
[112] Environmental Integrity Project et al., Closing the Floodgates: How the Coal Industry is Poisoning Our Water and How We Can Stop It (July 23, 2013), *available at* http://www.environmentalintegrity.org/news_reports/documents/2013_07_23_ClosingTheFloodgates-Final.pdf.
[113] *Id.* at 30.
[114] *Id.* at 7.
[115] *Id.*
[116] *Id.*
[117] *Id.*

Only about 63 percent of power plant permits required monitoring for one or more of the six pollutants.[118] Although some plants are required to monitor for several toxic pollutants, consistent and careful monitoring for all relevant pollutants is rare.[119] In short, the report demonstrates that permitting agencies have routinely turned a blind eye to these dangerous discharges while power plants have used our nation's waters as their own private dumping grounds.

D. EPA MUST FINALIZE ELGS THAT REFLECT STATE-OF-THE-ART TECHNOLOGIES AND PROTECT PUBLIC HEALTH AND THE ENVIRONMENT BY MAY 22, 2014.

EPA signed the current proposal on April 19, 2013 as a condition of a consent decree to resolve litigation brought to compel the agency to undertake overdue revisions of the ELG s.[120] EPA's proposal to set critically needed standards contains multiple options, including strong standards that would require the elimination of the majority of coal plant water pollution using technologies that are available and affordable. The strongest of these options—Option 5—would eliminate almost all toxic discharges, reducing pollution by more than 5 billion pounds a year. Option 4, the next strongest option, would eliminate new coal ash discharges and apply rigorous treatment requirements for FGD wastewater. By eliminating or significantly reducing toxic discharges from coal plants, a strong final rule would create hundreds of millions of dollars in benefits every year in the form of improved health and recreational opportunities for all Americans, in addition to the incalculable benefits of clean and healthy watersheds.[121] EPA estimates that ending toxic dumping from coal plants would cost less than one percent of annual revenue for most coal plants and at most about two pennies a day in expenses for ordinary Americans, if the utilities passed some of the cleanup costs to consumers.[122]

Although Options 4 and 5 would eliminate most toxic water pollution from coal plants, the proposed rule does not designate them as "preferred" options. Instead, the EPA's proposal includes so-called "preferred" options that would do next to nothing to curb dangerous pollution from FGD wastewater discharges and would leave other major waste streams unregulated– including large amounts of toxic bottom ash waste.

EPA has recognized for years that the 1982 ELGs are not adequate to protect the public, especially because they fail to control toxic metals in FGD wastewater, among other wastewater streams .[123] This recognition is directly at odds with the proposal of weak regulatory options,

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[118] *Id.* at 7-8.
[119] *Id.* at 9.
[120] *See Defenders of Wildlife v. EPA*, No. 1:10-cv-01915-RWR (D.D.C. filed Nov. 8, 2010).
[121] BCA at 12-2.
[122] *See* 78 Fed. Reg. at 34,501, table XI-9 (noting that the average annual cost to ratepayers for the most stringent option is $6.46).
[123] *See, e.g.*, Memorandum from James Hanlon, EPA, Director of the Office of Wastewater Management to EPA Water Division Directors, Regions 1-10 & Attachment A: Technology Based Effluent Limits, Flue Gas Desulfurization (FGD) at Steam Electric Facilities (June 7, 2010) (explaining that EPA is conducting a rulemaking to "address" this wastestream and that current controls are not adequate); 74 Fed. Reg. 55,837, 55,839 (Oct. 29, 2009).

and it appears that the expressed preference for these options does not actually reflect the views of the agency. The White House's Office of Management and Budget ("OMB") took the highly unusual and improper step of writing new weak options into the draft rule prepared by the EPA's expert staff during the inter-agency review process established by executive order.[124] A redline of the rule, showing the original EPA version and OMB's version reveals the changes: OMB refused to let EPA choose more protective options as "preferred" regulatory paths going forward, and inserted weaker options instead.[125] The result is that EPA's original two preferred options — Options 3 and 4 —were replaced with four preferred options: Options 3a, 3b, 3, and 4a, three of which were created by OMB. Through its revisions to the proposed rule, OMB eliminated Option 4 as a preferred option, taking positions directly contrary to those developed by EPA staff.[126] All of the preferred options that OMB inserted into the proposed rule are weaker than Option 4, meaning that through OMB's intervention the proposal has shifted away from the stringent controls that EPA has repeatedly recognized to be available and protective.[127] If EPA finalizes any of these lesser options (or is forced to do so by OMB), it will fail to control billions of pounds of pollution, possibly for decades to come.

Notwithstanding the weak options that EPA now puts forward as "preferred" options, EPA's underlying record for this rulemaking provides detailed analysis confirming that coal plants can make a shift away from leaking and unsafe impoundments to better and safer pollution controls, such as those incorporated into Options 4 and 5.[128] By transitioning to dry ash management systems and employing superior wastewater treatment technologies such as chemical precipitation, in combination with biological treatment or vapor compression, it is possible to reduce pollution from coal plants by billions of tons each year, even achieving zero liquid discharge.[129] After decades of delay, the Clean Water Act demands that EPA set strong, national standards to curb dangerous coal plant water pollution and protect public health and our waters. Under the terms of the consent decree, EPA must finalize the rule no later than May 22, 2014.

II. LEGAL FRAMEWORK

In the 1972 Clean Water Act amendments, Congress responded to the chronic failure of existing legislation to address water pollution effectively; Congress "was confronted by continuing and increasing massive pollution, which was turning many American rivers into open sewers, was threatening the extinction of marine life in several of the Great Lakes, as well as our ocean harbors, and was endangering the purity of our waters for drinking, for water recreation, for crop irrigation, and for industrial usage."[130] Pre-1972 versions of the Clean Water Act attempted to

[124] U.S. Envtl. Prot. Agency, Documentation of OMB Review Under Executive Order 12866.
[125] *See generally* EPA, Documentation of OMB Review Under Executive Order 12866 (June 2013), Docket No. EPA-HQ-LW-2009-0209 2237.
[126] *See id.* at 137, 144, 213-214, 226-227; *see also* Environmental Integrity Project et al., Closing the Floodgates, *supra* note 96, at 12-13.
[127] 78 Fed. Reg. at 34,458, 34,485-34,486.
[128] *See, e.g.*, TDD at 7-1-7-48.
[129] 78 Fed. Reg. at 34,485-34,486.
[130] *Am. Frozen Food Inst. v. Train*, 539 F.2d 107, 116 (D.C. Cir. 1976)*; see also Weyerhaeuser v. Costle*, 590 F.2d 1011, 1056 (D.C. Cir. 1978) ("Congress realized not only that its water pollution efforts until then had failed, but also that reliance on receiving water capacity as a crucial test for permissible pollution levels had contributed greatly to that failure.") (citations omitted).

control water pollution by determining "which polluter caused what pollution," a mandate that "proved over the years to be an impractical task."[131]

The modern Clean Water Act represents a "wholly new approach" to protecting our country's waterways.[132] Congress replaced a water-quality based framework that allocated responsibility for pollution that had already occurred with a technology-based framework that prohibits the discharge of pollutants without a permit. Technology-based effluent limitations are the centerpiece of the Act.

The Clean Water Act sets a national goal of eliminating water pollution.[133] To achieve the national goal, the Clean Water Act requires facilities to meet a series of increasingly stringent, technology-based effluent limitations. For pollutants the Clean Water Act classifies as either toxic (such as heavy metals) or "nonconventional" (such as nitrogen), the first standards were best practicable control technology ("BPT"),[134] followed by the more stringent best available technology ("BAT").[135] New sources are subject to the most stringent standards, new source performance standards ("NSPS").[136] The effluent limitations must be based on effluent guidelines ("ELGs"), which are nation-wide, minimum standards for categories of sources.[137] These national standards set a federal floor for environmental protection in order to avoid a "race to the bottom" by state regulators.[138] In developing BAT effluent guidelines, EPA must consider "the age of equipment and facilities involved, the process employed, the engineering aspects of the application of various types of control techniques, process changes, the cost of achieving such effluent reduction, non-water quality environmental impact (including energy requirements), and such other factors as the Administrator deems appropriate."[139]

A. THE BEST AVAILABLE TECHNOLOGY IS THE MOST STRINGENT POLLUTION CONTROL THAT IS AVAILABLE AND ECONOMICALLY ACHIEVABLE.

BAT represents the best available technology that is economically achievable:[140] a stringent treatment standard that has been held to represent "a commitment of the maximum resources economically possible to the ultimate goal of eliminating all polluting discharges,"[141] including requiring the elimination of discharges of all pollutants" if "such elimination is technologically and economically achievable."[142] A technology is "available" if it is in use in the industry, even if only by the best-performing plant in the industry, or if it can be demonstrated to be available

[131] *Am. Frozen Food Inst.*, 539 F.2d at 116.
[132] *Id.*
[133] 33 U.S.C. § 1251(a)(1).
[134] *Id.* § 1311(b)(1)(A).
[135] *Id.* § 1311(b)(2)(A).
[136] *Id.* § 1316(a)(1).
[137] *EI DuPont v. Train*, 430 U.S. 112, 127, 129 (1977).
[138] *See Natural Resources Defense Council, Inc. v. Train*, 510 F.2d 692, 709-10 (D.C. Cir. 1974) (explaining that Congress intended these uniform federal requirements to "safeguard against industrial pressures by establishing a uniform 'minimal level of control imposed on all sources within a category or class'").
[139] 33 U.S.C. § 1314(b)(2)(B).
[140] 33 U.S.C. § 1311(b)(2)(B).
[141] *EPA v. Nat'l Crushed Stone Ass'n*, 449 U.S. 64, 74 (1980).
[142] 33 U.S.C. § 1311(b)(2)(A).

through pilot studies or its use in other industries. A technology is economically achievable if the costs can be reasonably borne by the industry as a whole. EPA is precluded from basing its determination of BAT on a cost-benefit analysis.

1. *A treatment technology is "available" even if only in use at a single plant in the industry or can be demonstrated through pilot studies or use in another industry.*

Congress intended BAT to be "technology-forcing," *i.e.*, to drive the development and adoption of increasingly more effective pollution controls in order to "result in reasonable further progress toward the national goal of eliminating the discharge of all pollutants."[143] Courts have thus recognized that Congress intended for EPA to look to the best operating facilities in the relevant class to determine technological availability.[144] A technology need not even be in commercial use to be available, so long as the technology has been studied and demonstrated, such as through the use of pilot studies.[145] EPA may also conclude that a technology is available if it is in use in another industry, so long as it shows that that technology is transferable to the industry class for which it is establishing BAT.[146] This contrasts with the less-stringent BPT guidelines, which are based on the average of the best-performing plants.[147] In considering available technologies, EPA must consider technologies that lead to zero liquid discharges, in light of the statutory goal of eliminating water pollution.[148] Congress intended BAT to "push[] industries toward the goal of zero discharge as quickly as possible."[149]

2. *A treatment technology is economically achievable if the cost of adopting the technology can be reasonably borne by the industry, and EPA is precluded from basing its BAT determination on a cost-benefit analysis.*

A technology is economically achievable if the "costs can be reasonably borne by the industry."[150] Congress determined that investments in pollution controls are warranted to the greatest degree possible, and therefore the inquiry is not whether the costs of a given control are "worth it" in EPA's estimation. Instead, EPA's determination of economic achievability must be guided by the Supreme Court's holding that BAT limits "represent[] a commitment of the

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143 33 U.S.C. § 1311(b)(2)(A); *see also NRDC v. EPA,* 822 F.2d 104, 123 (D.C. Cir. 1987) (stating that "the most salient characteristic of this [CWA] statutory scheme, articulated time and again by its architects and embedded in the statutory language, is that it is technology-forcing").

144 *Chem. Mfrs. Ass'n v. EPA,* 870 F.2d 177, 226 (5th Cir. 1989) ("Congress intended these [BAT] limitations to be based on the performance of the single best-performing plant in an industrial field."); see also *NRDC v. EPA,* 863 F.2d 1420, 1426 (9th Cir. 1988); *Kennecott,* 780 F.2d at 448 ("In setting BAT, EPA uses not the average plant, but the optimally operating plant, the pilot plant which acts as a beacon to show what is possible.").

145 *See Am. Petroleum Inst. v. EPA,* 858 F.2d 261, 265 (5th Cir. 1988) (stating that under BAT, "a process is deemed 'available' even if it is not in use at all"); *FMC Corp. v. Train*, 539 F.2d 973, 983-84 (4th Cir. 1976) (finding EPA justified in setting BAT for chemical oxygen demand based on performance data from a single pilot plant).

146 *Kennecott*, 780 F.2d at 453 ("[p]rogress would be slowed if EPA were invariably limited to treatment schemes already in force at the plants which are the subject of the rulemaking."); *see also Reynolds Metals Co. v. EPA*, 760 F.2d 549, 562 (4th Cir. 1985).

147 *Chem. Mfrs. Ass'n,* 870 F.2d at 207-08.

148 *NRDC*, 822 F.2d at 123.

149 *Kennecott* v. EPA, 780 F.2d 445, 448 (4th Cir. 1985).

150 *Waterkeeper Alliance v. EPA*, 399 F.3d 486, 516 (2d Cir. 2005); *Rybachek v. EPA,* 904 F.2d 1276, 1290-91 (9th Cir. 1990) (discussing this standard).

maximum resources economically possible to the ultimate goal of eliminating all polluting discharges."[151] EPA determines BAT for categories of sources, rather than on a plant-by-plant basis,[152] and therefore considers costs to the industry as a whole.[153] While EPA must take into account the cost of achieving BAT,[154] EPA must set BAT limits based on the use of the best available technology.[155] In developing BAT guidelines, costs are to be given even less importance than in developing the less stringent BPT guidelines. Congress underscored this by including a requirement to balance costs against benefits in promulgating BPT guidelines, but omitting any cost-benefit analysis from the development of BAT guidelines.[156]

"[I]n assessing BAT, total cost is no longer to be considered in comparison to effluent reduction benefits."[157] As the D.C. Circuit has explained, Congress affirmatively rejected amendments which would have required cost-benefit balancing for BAT.[158] "Congress uses specific language when intending that an agency engage in cost-benefit analysis," and it did not allow cost-benefit analysis here.[159]

For decades, courts have rebuffed industry attempts to introduce cost-benefit analysis as a basis for EPA decision-making in the BAT process.[160] Thus, at least seven circuit courts of appeal have affirmed, in accord with the Supreme Court's decisive pronouncement in *Nat'l Crushed Stone*, that EPA cannot base BAT guidelines on cost-benefit analysis.

The Supreme Court's recent discussion of cost analysis under a separate Clean Water Act provision, 33 U.S.C. § 1326, in *Entergy Corp. v. Riverkeeper, Inc.*, 556 U.S. 208 (2009), reinforces this long-settled law. The question in *Entergy* was whether Section 1326, which requires the use of the "best technology available for minimizing [the] environmental impact" of

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[151] *EPA v. Nat'l Crushed Stone Ass'n*, 449 U.S. 64, 74 (1980).
[152] *Train*, 430 U.S. at 127.
[153] *See Am. Iron & Steel Institute v. EPA*, 526 F.2d at 1051 (cost must be considered "on a class or category basis, rather than [on] a plant-by-plant basis").
[154] 33 U.S.C. § 1314(b)(2)(B).
[155] *See Am. Iron & Steel Inst. v. EPA*, 526 F.2d 1027, 1051 (3d Cir. 1975); *Chem. Mfrs. Ass'n*, 870 F.2d at 204.
[156] *Compare* 33 USC 1314(b)(1)(B) *with* 33 USC 1314(b)(2)(B).
[157] *EPA v. Nat'l Crushed Stone,* 449 U.S. 64, 71 (1980); see also *Am. Iron & Steel,* 526 F.2d 1027, 1051-52 (3rd Cir. 1975) ("With respect to the [BAT] standards," Congress intended "that there should be no cost-benefit analysis.").
[158] *See Weyerhauser v. Costle*, 590 F.2d 1011, 1046 (D.C. Cir. 1978).
[159] *Am. Textile Mfrs. Inst., Inc. v. Donovan*, 452 U.S. 490, 511 (1981); *see also id.* at 511 n.30 (reaffirming *Nat'l Crushed Stone*).
[160] *See, e.g., id.* at 1053 n.54 ("a cost-benefit analysis is not required at all" for BAT); *CPC Int'l Inc. v. Train*, 540 F.3d 1329, 1341-42 (8th Cir. 1976) (BAT guidelines are "governed by a standard of reasonableness without the necessity of a thorough cost-benefit analysis"); *Reynolds Metals Co v. EPA*, 760 F.2d 549, 565 (4th Cir. 1985) ("no balancing is required" for BAT); *Rybachek v. EPA*, 904 F.2d at 1290-91 (EPA "need not compare [control] cost with the benefits of effluent reduction"); *BP Exploration & Oil, Inc. v. EPA,* 66 F.3d 784, 799-800 (6th Cir. 1995) (rejecting industry demand for cost-benefit analysis because BAT "does not require cost-benefit analysis" and "EPA need only find … that the cost of the technology is reasonable"); *Texas Oil & Gas Ass'n v. EPA*, 161 F.3d 923, 928 (5th Cir. 1998) (underlining that "BAT is the CWA's most stringent standard" and must be set based not on cost-benefit analysis but on "the performance of the single, best-performing plant in an industrial field"); *Waterkeeper Alliance v. EPA*, 399 F.3d at 516 (BAT can be set to the level which can "reasonably be borne by a given industry"); *Am. Paper Inst. v. Train*, 543 F.2d 328, 348 (D.C. Cir. 1976) ("Section 304(b)(2)(B) mandates no such [cost-benefit] balancing for the 1983 limitations"); *Ass'n of Pac. Fisheries*, 615 F.2d at 805 ("The conspicuous absence of the comparative language contained in section 304(b)(1)(B) leads us to the conclusion that Congress did not intend the Agency or this court to engage in marginal cost-benefit comparisons [for BAT].").

cooling water intake structures allowed EPA discretion to apply cost-benefit analysis to set that particular technology-based standard; the Court held that it did.[161] Having settled that question based on its reading of the statutory text of Section 1326, the Court, in dicta, went on to compare the Section 1326 standard with BAT. In doing so, it emphasized that the Section 1326's goal of "minimizing" environmental impact is "relatively modest" compared with BAT's goal of "eliminating the discharge of all pollutants," meaning that it was more reasonable to allow cost-benefit balancing in connection with the Section 1326 standard than with the more stringent BAT standard.[162] *Entergy* ultimately affirmed that only certain specific Clean Water Act standards "authorize cost-benefit analysis," and the BAT analysis does not fall within this group. This analysis is consistent with the long line of cases over the past forty years that have held cost-benefit analysis is not permitted in BAT standard-setting, including the Supreme Court's ruling in *National Crushed Stone*.[163]

Congress declined to premise BAT standards on cost-benefit analysis for sound policy reasons. The sponsors of the 1972 Clean Water Act amendments recognized that the costs of pollution controls are more easily quantified than the benefits; Congress understood that while the cost of compliance are "readily quantifiable," "[s]ome economic benefits can be calculated with reasonable accuracy," but many more benefits are "difficult to calculate."[164] As the costs are more easily quantified and monetized than the benefits, any cost-benefit analysis will be biased toward emphasizing costs over benefits.

B. EFFLUENT LIMITATIONS GUIDELINES CANNOT EXEMPT DISCHARGES OF EXISTING WASTE.

EPA' proposal would have any new BAT limits apply to only waste water generated after a date in 2017 or beyond.[165] Under all proposed options, BAT limits would not apply to wastes generated before that date, so-called "legacy wastes."[166] EPA is considering going one step further and establishing separate BAT limits for legacy wastes that would be equal to the existing BPT limits.[167]

In promulgating effluent limitations guidelines, EPA must apply the guidelines to discharges of all pollutants and has no authority to exempt discharges based on when the waste was created. EPA has an obligation to establish BAT guidelines that eliminate, or reduce, the discharge of pollutants for categories of sources – without regard to when the waste was generated. Effluent limitations shall be achieved for "categories and classes of point sources."[168] The effluent limitations "shall require the elimination of discharges of all pollutants" if EPA finds that "such elimination is technologically and economically achievable for a category or class of point sources."[169] If a zero discharge standard is not achievable, the effluent limitations must require

[161] 556 U.S. at 219-220.
[162] *See id.* at 221-222.
[163] *See id.* at 222.
[164] S. Rep. 92-414 (1972), in 1972 U.S.C.C.A.N. 3668, 3713-14.
[165] *E.g.*, 78 Fed. Reg. at 34,522-23.
[166] Id.
[167] Id.
[168] 33 U.S.C. § 1311(b)(2)(A).
[169] *Id.*

the best available technology economically achievable "for such category or class."[170] Similarly, EPA must identify "the degree of effluent reduction attainable" through the best control measures "for classes and categories of point sources."[171] The statute contains no distinction between pollutants based on when they were produced; the statute does not distinguish between legacy and newly generated wastes.

Moreover, the basic structure of Clean Water Act regulation of point sources focuses on regulating discharges of pollutants regardless of when the pollutants were generated. The regulatory structure begins with the prohibition on discharging any pollutant except in compliance with various provisions of the Act.[172] One of those exceptions is compliance with an NPDES permit.[173] NPDES permits are required for any "discharge of a pollutant," which is defined as "any addition of any pollutant to navigable waters from any point source."[174] NPDES permits, in turn, have to comply with the effluent limitations in section 1311.[175] And section 1311 requires, where feasible, effluent limitations that require the elimination of discharges, and, where not feasible, effluent limitations resulting in further progress toward eliminating discharges.[176] The term "discharge" is used throughout the statutory sections regulating point sources and indicates that the focus is on controlling, and ultimately eliminating, the discharge of pollutants to navigable waters. The statutory scheme does not give EPA authority to exempt a discharge from achieving BAT limits simply because the facility discharges pollutants that were produced in the past.

C. EFFLUENT LIMITATIONS MUST REQUIRE COMPLIANCE WITHIN THREE YEARS OF PROMULGATION OF THE FINAL RULE.

Compliance with BAT shall be "as expeditiously as practicable, but in no case later than three years after the date such limitations are promulgated . . . , and in no case later than March 31, 1989."[177] EPA must "provid[e] guidelines for effluent limitations, and, at least annually thereafter, *revise*, if appropriate, such regulations."[178] The plain language of the Clean Water Act states that compliance with initial regulations must occur within three years of promulgation and in no case later than March 31, 1989 and compliance with revised ELGs must occur within three years. The three-year compliance deadline applies not only to the initial BAT limits but to each subsequent revision.[179] Therefore, when EPA finalizes this rule, all facilities must achieve compliance within three years of promulgation of the rule.

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170 *Id.*
171 *Id.* § 1314(b)(2)(A).
172 33 U.S.C. § 1311(a).
173 *Id.* § 1342(a).
174 *Id.* § 1362(12).
175 *Id.* § 1342(b)(1)(A).
176 *Id.* § 1311(b)(2)(A).
177 33 U.S.C. § 1311(b)(2)(C), -(D).
178 *Id.* § 1314(b) (emphasis added).
179 The plain language of the Act, and its objective of eliminating all discharges of pollutants, indicate that the three-year compliance deadline applies to all subsequent revisions of the effluent limits, rather than to only the initial limits. *See infra* Section XIII.

III. BEST AVAILABLE TECHNOLOGY DETERMINATION FOR FLUE GAS DESULFURIZATION WASTEWATER

A. CHEMICAL PRECIPITATION PLUS MECHANICAL EVAPORATION IS BAT FOR FGD WASTEWATER.

EPA should set BAT limits for FGD wastewater based on chemical precipitation plus mechanical evaporation for all facilities regardless of size.[180] The BAT standard requires achievement of 'effluent limitations . . . which . . . shall require application of the best available technology economically achievable . . . , which will result in reasonable further progress toward the national goal of eliminating the discharge of all pollutants."[181] According to the CWA's legislative history, the starting point for identifying BAT is not the average plant, but the "single best performing plant in an industrial field" in terms of its capacity to reduce pollutant discharges.[182] EPA may look to technologies in use in other industries that could be transferred to the industry in question and may also consider technologies that have not been implemented in full scale but have been shown to be viable in research.[183]

The leading technology for treatment of FGD wastewater—and the only one that will push the industry towards the national goal of zero liquid discharge as soon as possible—is chemical precipitation, followed by vapor-compression evaporation and crystallization, which we will refer to as "mechanical evaporation."

Mechanical evaporation is also the only technology evaluated by EPA that addresses all pollutants present in the FGD waste stream, as EPA itself acknowledges in the Proposed Rule: "Option 5 would control other pollutants in FGD wastewater that Options 1 through 4 do not effectively control, namely boron, bromides, and TDS.[184] An industry study conducted six years ago also concluded that "[mechanical] [e]vaporation is a comprehensive means of dealing with FGD wastewaters, resulting in the capture of essentially all of the water's pollutants and returning clean water to the process or other plant uses."[185] Mechanical evaporation is the BAT option required by this record, because as EPA notes, "without question, Option 5 would remove the most pollutants from steam electric power plant discharges."[186] EPA cannot elect to ignore boron, bromides, and TDS. Because a feasible technology exists to curb harmful discharges of boron, bromides, and TDA, EPA must select that technology as BAT both as a matter of law under the Clean Water Act and responsible public health policy.

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[180] EPA's proposed 50 MW threshold is not supported by the record. Only one plant with an FGD wastewater stream is smaller than 50 MW, which results in an unreasonably high cost estimate for that category. *See* EPA-HQ-OW-2009-0819-2258, at Table 7. Figures 5 and 6 in that document do not show any relationship between plant size and the cost per MW of installing an FGD treatment system.

[181] 33 U.S.C. § 1311(b)(2)(A).

[182] *Chem Mfrs. Ass'n v. EPA*, 870 F.2d 177, 239 (5th Cir. 1989) (*citing* Congressional Research Service, *A Legislative History of the Water Pollution Control Act Amendments of 1972* at 170 (1973) at 170).

[183] These determinations, arising out of the CWA's legislative history, have repeatedly been upheld by the courts. *E.g., Am. Petroleum Inst. v. EPA*, 858 F.2d 261, 264–65 (5th Cir. 1988); *Pac. Fisheries*, 615 F.2d at 816–17.

[184] 78 Fed. Reg. at 34,477.

[185] Electric Power Research Institute, Treatment Technology Summary for Critical Pollutants of Concern in Power Plant Wastewaters, Jan. 2007 ("EPRI 2007"), Docket No. EPA-HQ-OW-2009-0819-2168, at 4-3.

[186] 78 Fed. Reg. at 34,473.

1. Mechanical evaporation is technologically available.

EPA states that although Option 5 is not a preferred option, "the technologies are all technologically available."[187] We strongly agree. Mechanical evaporation has been used for over 30 years in many industries, including for treatment of cooling tower blowdown and coal gasification wastewaters. According to a 2007 industry study, vapor compression and falling film evaporators (also known as brine concentrators) "have been the workhorse for dealing with cooling tower blowdown and other power plant wastewaters."[188] As of 2008, there were 146 mechanical evaporation installations in the United States.[189] As described in the Synapse report,[190] there are several major manufacturers of zero liquid discharge systems, including Veolia, Aquatech, and GEA Processing Engineering, GE Power and Water, and numerous smaller vendors. These products have been applied across a large range of industries, showing the adaptability of these systems.

While FGD wastewaters have some different characteristics than these wastewaters, the industry is quickly adapting the technology for use on FGD wastewaters. The different characteristics of FGD wastewater require careful pretreatment, but they do not render mechanical evaporation infeasible.[191] The main pretreatment methods are physical/chemical treatment to reduce solids, and softening, which causes "magnesium and calcium ions [to] precipitate out of the wastewater and [be] replaced with sodium ions, producing an aqueous solution of sodium chloride that can be more effectively treated with a forced-circulation crystallizer."[192]

Alternatively, the softening step can be eliminated altogether through the use of low-temperature vacuum crystallization, which directly crystallizes the highly soluble salts found in FGD wastewater.[193] Such "cold crystallization is a common process in industrial salt crystallization, having been widely applied over the last half century." Cold crystallization has capital and energy costs comparable to current evaporation and crystallization processes, but significantly reduces expenditures for chemicals and sludge disposal costs by eliminating the softening pre-treatment step.

Mechanical evaporation treatment systems for FGD wastewater are operating at no fewer than four plants in Italy and one plant in the United States. At least two more full-scale systems are in planning or construction stages in the United States. The systems in Italy have been operating for five to seven years without any significant problems. The Enel's Federico II plant in

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[187] 78 Fed. Reg. at 34,477.
[188] EPRI 2007, Docket No. EPA-HQ-OW-2009-0819-2168, at 4-3.
[189] Summary of Zero Liquid Discharge Waste Management Installations, Docket No., EPA-HQ-OW-2009-0819-1224, Attachment 4.
[190] Synapse Report, Appendix A, at 49.
[191] *See* EPRI 2007, Docket No. EPA-HQ-OW-2009-0819-2168, at 4-3 ("Due to the more concentrated nature of FGD blowdown streams plus the presence of trace metals and other pollutants in reatively high concentrations, common evaporation systems and processes will have to be modified to accommodate the characteristics of the FGD waters.").
[192] TDD at 7-13.
[193] Shaw, William A., Low Temperature Crystallization Process is the Key to ZLD Without Chemical Conditioning, IWC-10-39, at 479.

Brindisi, Italy has a particularly strong record of performance with a vapor compression and crystallization system, and was selected by EPA as the leading plant for setting effluent limits based on this technology.[194] The record describes in detail two other Italian plants operating mechanical evaporation systems for FGD wastewater. The Monfalcone Power Station decided in 2007 to install a system manufactured by HPD/Veolia.[195] The Torrevaldaliga Nord plant comprises three 660 MW units burning bituminous coal, and equipped with baghouses, SCR, and limestone forced oxidation wet FGD scrubber. FGD blowdown occurs with solids at 15-18 percent, and chlorides at 15,000 to 25,000 parts per million, similar to practices at plants in the United States. Both the distillate and concentrate streams are recycled back into the scrubber resulting in a zero discharge system.

The Kansas City Power & Light Iatan plant in Missouri is a 2-unit, 1520 MW plant that burns low sulfur coal and discharges to the Missouri River. The FGD wastewater treatment system was designed by Aquatech and began operating in March 2009. The FGD blowdown is pretreated with hydrocyclones to reduce TSS concentrations from 30,000 to 20 ppm, and then treated with caustic, an antifoaming agent, and seeded calcium sulfate to prevent scaling.[196] The wastewater then enters parallel brine concentrators, which produce a distillate that is 85 percent of the volume FGD blowdown water—all of which is returned to the reclaim water system.[197] The evaporation system concentrates the brine by a factor of seven."[198] However, because there is no softening pretreatment to remove calcium and magnesium, the plant does not operate a final drying/crystallization process. Instead, the concentrate from the brine process is combined with fly ash in a pugmill and landfilled.[199]

In addition to these plants where mechanical evaporation systems are already operating, similar systems are in various stages of design and construction at two coal plants in the United States: Duke Energy's Mayo Station in North Carolina, Duke Energy's Roxboro Station in North Carolina, and Public Service Company of New Hampshire's Merrimack Station.

Under a consent decree with the state, Duke Energy has committed to constructing a zero liquid discharge system at its Mayo plant.[200] Duke Energy has selected a mechanical evaporation system designed and supplied by GEA Progress Engineering Inc., which will consist of a falling film evaporator, followed by a secondary forced circulation evaporator. The brine will be mixed with fly ash for on-site landfilling, while the distillate water will be reused at the plant to reduce

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[194] TDD at 13-19.

[195] Press Release, Sept. 22, 2009, HPD awarded Flue Gas desulfurization (FGD) Effluent treatment for Monfalcone coal-fired generating station. The system involves a clarification and softening pretreatment to remove solids, calcium, magnesium, and heavy metals followed by falling film evaporation, and brine crystallization. The plant burns a Russian bituminous coal with a sulfur content between 0.3 and 0.4 percent. Final Monfalcone Site Visit Notes, Docket No. EPA-HQ-OW-2009-0819-1784.

[196] Iatan Final Site Visit Notes, Docket No. EPA-HQ-OW-2009-0819-1889, at 1-5.

[197] *See* Written responses to EPA questions regarding the evaporation system for treating FGD wastewater [EPA-HQ-OW-2008-0517].

[198] Final Iatan Site Visit Notes, Docket No. EPA-HQ-OW-2009-0819-1889, at page 4.

[199] *See* Written responses to EPA questions regarding the evaporation system for treating FGD wastewater, Docket No. EPA-HQ-OW-2008-0517, DCN 06287A4. The only operational problems identified with this system resulted from injecting water with over four times the design TDS value of 15,000 ppm.

[200] North Carolina Department of Envt. And Nat. Resources, Special Order by Consent, Mayo Steam Electric Plant, June 26, 2012, ¶2.a(1).

freshwater demand.[201] Duke Energy is also installing a mechanical evaporation system designed by GEA Processing Engineering at the Roxboro plant, to avoid violations drinking water standards for TDS and chloride in the small lake receiving its FGD wastewater.[202] As of November 2011, GEA was doing final equipment design and balance of plant design at both plants.[203] Although cost estimates are not public, the costs were "at the level that [the utility] [is] comfortable getting the job in at."[204]

At Merrimack Station in New Hampshire, Public Service Company of New Hampshire ("PSNH") chose to install an Aquatech zero liquid discharge ("ZLD") system, even while EPA Region 1 was still considering a biological treatment system to be BAT.[205] That PSNH did so is a testament to the proven technological feasibility of such systems. On November 17, 2010, PSNH hired Burns & Macdonald to provide technical assistance on the ZLD project, based on that firm's experience at the one other ZLD project in the United States, presumably the Iatan Station.[206] Burns & Macdonald "concluded the installation of a brine concentrator, crystallizer would reduce the liquid waste stream to between zero to five gpm, which may allow for re-use and an additional crystallizer, and dewatering device will be installed to insure zero discharge."[207] Once PSNH had decided to proceed with a ZLD system, the process moved quickly. A request for proposal for equipment was released in early January 2011, and by February 3, 2011, a purchase order had been opened with Aquatech.[208] An RFP for construction was released in spring 2011.[209] PSNH completed commissioning, testing, and performance demonstration of the zero discharge technology in June 2012, and the system went into service on June 21, 2012. This mechanical evaporation system has therefore been in service for over a year.[210]

This experience demonstrates that mechanical evaporation is technologically feasible for treatment of FGD wastewater. Not only is it in use at a half-dozen plants, but the performance of the system at those plants has sufficiently impressed two other plants in the United States to install mechanical evaporation systems.

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[201] Zero-Liquid Discharge System at Progress Energy Mayo Generation Station, EPA-HQ-OW-2009-0819-1443, at page 1.
[202] Deposition of Thomas E. Higgins, CH2M Hill, in Tennessee Clean Water Network v. Tennessee Dept. of Envt. & Conservation, Case No. WPC10-0116 (Feb. 16, 2012), at 122, 134-35. Dr. Higgins was an expert witness for Tennessee Valley Authority with respect to the wastewater treatment at the Bull Run plant. *Id.* at 13, 52.
[203] *Id.* at 123.
[204] *Id.* at 123-24.
[205] *See* Investigation of PSNH Installation and Cost Recovery of Scrubber Technology at Merrimack Station, Final Report of Jacobs Consultancy (2012), at 15-17. Merrimack Station is a two-unit, 458 MW plant burning eastern bituminous coal.
[206] *See* Jacobs Consultancy, Redacted New Hampshire Clean Air Project Due Diligence on Completed Portion (2011) at 67.
[207] *Id.*
[208] *Id.*
[209] *Id.*
[210] PSNH Progress Report, Merrimack Station Scrubber Project, June 28, 2012, Docket No. DE 11-250, at 2, Exhibit FGD-21.

2. *Mechanical evaporation of FGD wastewaters is economically achievable.*

a. EPA's estimated cost for mechanical evaporation is too high.

EPA estimated the total capital cost for adding mechanical evaporation to 116 plants at $6.24 billion, or approximately $54 million per plant.[211] EPA's estimate is higher than other publicly available information about the installation cost of these systems.[212] The Aquatech mechanical evaporation system at Merrimack has been estimated to between $23 million[213] and $37 million.[214] At the Torrevaldaliga Nord plant in Italy, the cost of the wastewater treatment system was estimated at €10 million, which according to present conversion rates is between $13 and $14 million dollars.[215] Since Italian law prohibits discharges of FGD wastewater to the sea, the demand for zero-liquid discharge systems has been substantial, which has likely lead to declining costs, much as would occur in the United States if EPA selected Option 5.

EPA Region 1 estimated the operations and maintenance (O&M) costs for a mechanical evaporation system in its BAT determination for Merrimack Station. For that plant, where the FGD wastewater flow volume is estimated to be approximately 70,000 gallons per day, or 750 gallons per minute,[216] EPA calculated O&M costs of approximately $1.524 million.[217] By comparison, EPA's estimate of average O&M costs in the proposed rule is approximately $8.8 million per facility.[218]

There are several causes of inflation of EPA's cost estimate for mechanical evaporation. First, the capital cost appears to include "sludge disposal costs," which is properly counted as an O&M cost.[219] Indeed, EPA also included "sludge disposal costs" as an O&M item, apparently

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[211] TDD at 9-28.

[212] These cost differences may reflect the volume of FGD flow being treated, but as plant-by-plant information has been withheld as confidential, we are unable to fully investigate EPA's cost assumptions.

[213] *See* Expert Report of John H. Koon in the Matter of Comments on the NPDES Permit for PSNH's Merrimack Station (2012) at 9 (In January 2011 project management personnel revised the project budget to include $20.2 million for the supplemental WWTS."); *see also id.* at 10 ("The cost of VCE by itself was calculated to be $23,080,000 by subtracting the cost for chemical precipitation from the EPA cost estimate for 'Chemical Precipitation/Softening plus Evaporation.'").

[214] 2012 Jacobs Consultancy Report, at Figure 8 ($32.6 million for secondary wastewater treatment system, plus $3.8 million for soda ash softening process). EPA's own estimate for the capital cost was $27,949,000. U.S. EPA Region 1, Determination of Technology-Based Effluent Limits for the Flue Gas Desulfurization Wastewater at Merrimack Station in Bow, New Hampshire (Sept. 23, 2011) at 22. To put this cost into perspective, $23 million is only around 5% of the total project cost for installing the FGD system. Furthermore, the annual cost as a fraction of operating revenue for the plant was only 1.5%. Expert Report of John Koon, Merrimack, at Table 4. It has also been estimated that the capital cost of the mechanical evaporation system increases the value of the plant by between 1.4 and 4.7%, a critical fact relating to affordability for the large portion of the electric generating sector for which rates guarantee a certain rate of return on the value of these assets. *Id.* at 11 ("The capital cost of VCE would increase the value of the site facilities by 1.4 to 4.7%, depending on the basis for the comparison.").

[215] Enel Site Visit Notes, Docket No. EPA-HQ-OW-2009-0819-1795.

[216] Merrimack TBEL Determination at 18.

[217] *Id.* at 22.

[218] TDD at 9-28 (Table 9-3) (value is $1.03 billion divided by 116, the number of plants). Calculating average O&M costs is less than ideal, since O&M depends largely of FGD wastewater flow rates, but since EPA has withheld as confidential plant specific cost or flow information, this average is the only available plant-based cost estimate.

[219] TDD at 9-26.

double-counting this cost. Second, EPA's cost estimates for mechanical evaporation include the cost of a forced-circulation crystallizer,[220] which is likely more expensive than the alternative methods to eliminate brine concentrate such as ash conditioning, in which the concentrate is mixed with fly ash to stabilize the material for landfilling.[221]

Third, EPA's industry-wide cost estimate does not account for the many plants that could comply with these standards without installing any mechanical evaporation technology at all, but simply by adopting different design and operating practices. As discussed in Section 7.1.6 of the TDD, and in even greater detail in EPA's 2009 Detailed Study, there are at least five design and operating practices currently in use that can eliminate the discharge of FGD wastewater: (1) evaporation ponds, which are most effective in arid climates; (2) conditioning dry fly ash; (3) underground injection, (4) variations of complete recycle, and (5) operation of both wet and dry FGD scrubber systems, recycling the treated wastewater from the wet system into the dry one.[222] EPA's data show that almost one-fifth of plants achieve zero discharge through these methods.[223] According to the 2009 Detailed Study, 38 percent of plants operating wet FGD systems already have zero liquid discharge of FGD wastewater, either through mechanical evaporation, or design/operating practices.[224]

Despite this record, EPA's cost analysis did not account for plants that are already achieving zero discharge for FGD wastewater; instead, it assumed that every plant with an FGD wastewater stream, other than the one plant already operating a mechanical evaporation system (Iatan), would have to install this technology.[225] By ignoring existing zero discharge systems other than mechanical evaporation, EPA's industry-wide cost analysis is overstated. Moreover, EPA's cost estimate ignores that many other plants would investigate whether one of these design and operating practice changes is feasible for their plant, and many would select these types of changes over installing a mechanical evaporation system. Thus, EPA did not account for potential implementation of these design and operating changes across the industry in its cost analysis.

EPA's estimate of the industry-wide cost for Option 5 – $2.3 billion – is EPA's worst-case cost estimate for Option 5. This is a pre-tax estimate, but EPA itself states that "after-tax costs are a more meaningful measure of compliance impact on privately-owned for profit plants,"[226] which account for 71.6 percent of the generating capacity subject to the rule.[227] EPA's after-tax estimate for Option 5 is only $1.548 billion.[228] If total industry cost were a relevant factor, which it is not, EPA should be using the after-tax figure of $1.548 billion, rather than $2.3 billion.

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[220] *Id.* at 9-26.
[221] *Id.* at Section 7.1.4.
[222] *Id.* at 7.1.6; *see also* 2009 Detailed Study, Docket No. EPA-HQ-OW-2009-0819-0387, at 4-36.
[223] TDD at 7-17.
[224] 2009 Detailed Study, Docket No. EPA-HQ-OW-2009-0819-0387, at 4-47, Fig. 4-9.
[225] Incremental Cost and Loading, at 4-13.
[226] RIA at 3-6.
[227] *Id.* at Table 2-3.
[228] *Id.* at t 3-6.

Finally, EPA's industry-wide cost estimate does not reflect anticipated unit retirements or conversions, *id.*, that would occur after December 31, 2014,[229] even though many of those retirements would happen before the first year in which EPA assumes that the technologies would be implemented—2017.[230] This arbitrary cut-off date excludes the entire class of plants that are likely to shut down or switch to natural gas just before the MATS compliance deadline of April 2015.[231] A number of these plants slated for retirement, but included in EPA's analysis, have wet FGD systems, as shown in Table 2.

Table 2 – Wet-Scrubbed Units that Have Announced Retirement But Were Included in EPA's Cost Analysis

State	Plant Name and Units	Retirement Date
KY	Big Sandy Unit 2	2015
AL	Colbert Units 1-5	2016 for Units 1-4, 2018 for Unit 5
NY	Danskammer	2012
IN	Harding Street Units 5, 6	2016
PA	Hatfield's Ferry Units 1-3	2013
OH	Muskingum River Unit 5	2015
NV	Reid Gardner Units 1-4	2014 for Units 1-3, 2017 for Unit 4
IN	Tanners Creek Unit 4	2015
PA	Mitchell Power Station Unit 3	2013
PA	Shawville Units 3, 4	2015
GA	Yates Units 1, 6, 7	2015
Source: --EIA Form 860 (2012) (generating unit size); --National Electric Energy Data System Annual Coal Unit Characteristics (2012) (sulfur dioxide control technology installed) -- List of Announced Retirements Included in EPA's Cost Calculations (retirement date)		

Accounting for these additional retirements and conversions would lower the industry-wide cost of all options.[232]

b. EPA's conclusion that the total industry cost of Option 5 is too high is not supported by the record and is an improper basis for rejecting this option.

EPA never evaluates whether the costs of mechanical evaporation are economically achievable by the industry, and there is nothing in the record to demonstrate that it is not. Instead of applying this well-establish standard for economic achievability, EPA rejected Option 5 based on the total cost to industry, which it calculated at $2.3 billion in annualized social costs, and

[229] EPA-HQ-OW-2009-0819-2149, at 2.
[230] RIA at Table 3-1.
[231] List of Announced Retirements Included in EPA's Cost Calculations, submitted by Commenters as an exhibit to this letter.
[232] A plant that converts to run on natural gas would no longer need to operate its wet FGD system.

"because of preliminary indications that it may not be economically achievable."[233] EPA notes that while affordability to the industry is the relevant cost factor for BAT, at isolated times it has considered total industry cost.

The previous rulemakings to which EPA cites as precedent for this approach do not demonstrate that total industry cost is a valid basis for concluding whether a technology is economically achievable. For instance, a 2009 rulemaking on the construction and development point source category, EPA rejected options for sediment control that would have cost $4.9 billion and $9 billion because they would provide only marginally greater removals than the preferred option costing just under $1 billion.[234] In that rulemaking, as well as in this one, total industry cost is merely a guise for incremental cost-benefit decision making. EPA may not base its BAT determination on the cost effectiveness of the technology in question, *see supra* Section II. However, a comparison to the 2009 rulemaking in fact demonstrates the relative cost-effectiveness of Option 5 and mechanical evaporation. While Option 5 costs three times more than Option 4,[235] it removes over 10 times as much pollution from our waterways.[236]

The statutory mandate to consider cost in setting BAT has been interpreted definitively by the courts. With respect to cost, the relevant inquiry for EPA is whether "costs can be reasonably borne by the *industry*."[237] The inquiry is *not* whether the costs of a given control are warranted in EPA's estimation, or whether the costs are "high" in an abstract and subjective sense. Total industry cost, taken out of the context of the industry's size and revenues,[238] is an arbitrary metric and an inappropriate basis to reject a technologically feasible option as BAT.[239] Here, EPA's assessment that the total industry cost is too high is totally unmoored from any standards governing what total costs are acceptable; thus, total industry cost is not only the wrong cost test for determining BAT, it is wholly arbitrary in application.

EPA's other economic basis for rejecting Option 5 is the vague assertion that based on "certain screening-level economic impact analyses," "compliance costs may result in financial stress to some entities owning steam-electric plants.[240] In fact, as discussed below in Section IX, EPA's own screening-level analysis demonstrates that the costs of Option 5 can be borne by the industry. That some entities may experience some degree of financial stress is not a reason to reject mechanical evaporation as BAT.[241]

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[233] 78 Fed. Reg. at 34,473.

[234] Effluent Limitations Guidelines and Standards for the Construction and Development Point Source Category, 74 Fed. Reg. 62,996, 63,026.

[235] TDD at Table 9-3 (comparing total capital costs).

[236] TDD at Table 10-9.

[237] *Waterkeeper Alliance v. U.S. EPA*, 399 F.3d 486, 516 (2nd Cir. 2005) (emphasis added); *see also Rybachek v. U.S. EPA*, 904 F.2d 1276, 1290-91 (9th Cir. 1990) (discussing this standard).

[238] *See* Synapse Report, Appendix A, at 48.

[239] In addition, the affordability of an option combining BAT proposals for various waste streams is an inappropriate basis to conclude that a particular technology is not economically achievable for the waste stream it is designed to address. Economic achievability should be determined on the waste stream level, not the option level.

[240] 74 Fed. Reg. at 34,473.

[241] *See infra* bottom ash section, discussing some plant closures not a barrier to BAT.

3. *The other BAT factors do not alter the conclusion that BAT limitations should be based on the use of mechanical evaporation.*

While the BAT analysis begins with the best performing pollution reduction technologies, the statute also specifies the following factors that EPA must "take into account" in determining the BAT:

> . . . the age of equipment and facilities involved, the process employed, the engineering aspects of the application of various types of control techniques, process changes, the cost of achieving such effluent reduction, non-water quality environmental impact (including energy requirements), and such other factors as the Administrator deems appropriate.[242]

EPA's record demonstrates that the age of the facility does not impair the suitability of mechanical evaporation for treating the FGD wastewater stream. Based on extensive industry surveys, it was determined that "the age of the plant and generating unit(s) do not impact the plants' ability to install the treatment technologies proposed as part of this rulemaking because the treatment system for the FGD wastewater is distinctly separate from the generating unit."[243] Mechanical evaporation, like the other technologies EPA considered, is a separate and self-contained process that does not affect the operation of the boilers or the other production processes at the facility.

In its permitting decision for the Merrimack plant in New Hampshire, EPA Region 1 concluded that the age of the power station would not preclude or create particular problems for operation of the mechanical evaporation system; that the system would not interfere with other production processes; and that it did not present any engineering issues.[244] The same conclusions can be drawn based on the present record, when making the BAT determination for the industry as a whole.

The type of coal burned in a generating unit affects the concentrations of chlorides, dissolved solids, and metals in the FGD blowdown. However, the pre-treatment steps that EPA has evaluated as part of the mechanical evaporation technology option are designed to bring each of these components into the range suitable for the brine concentration system. Therefore, no upstream process changes are required for proper operation of the mechanical evaporation system.

Another BAT factor to be considered is non-water-quality environmental impacts. While operating a mechanical evaporation system does require more energy than a passive settling pond, the current inadequate treatment method in use at many plants, the amount of energy is negligible compared to the energy output of the power station. For the Merrimack plant, it was calculated that the evaporation system consumed only 0.8 percent of the energy generated by that station.[245] Moreover, there are energy savings associated with generation of a relatively clean

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[242] 33 U.S.C. § 1314(b)(2)(B); *see also* 40 C.F.R. § 125.3(d)(3).
[243] ERG Non-CBI Subcategorization Memo, EPA-HQ-OW-2009-0819-2258, at 5.
[244] Merrimack TBEL Determination at 22.
[245] Expert Report of John Koon, Merrimack at p. 12 & Table 5.

distillate stream by the mechanical evaporation system, which represents water that does not have to be pumped from a nearby water body, treated, or transported long distances—all of which consume energy.

In addition, the mechanical evaporation system does generate a small amount of solid waste—at the Merrimack plant, the volume attributable to the evaporation system was about 5,000 tons per year. To put this number is perspective, the plant was also estimated to generate 187,000 tons per year of gypsum as a byproduct of the FGD system and 94,566 tons of ash per year.[246] Thus, the additional solid waste created by the ME system at Merrimack was less than 2 percent of the plant's total solid waste.[247] Moreover, technologies like cold crystallization eliminate the solid waste produced through the softening pre-treatment.

Thus, none of the statutory BAT factors demonstrate that mechanical evaporation is not technologically or economically achievable.

4. *The public health and economic benefits of mechanical evaporation are much larger than EPA has estimated*

EPA acknowledges that only mechanical evaporation will address the high levels of boron, bromides, and TDS in FGD wastewater. Based on the mechanical evaporation technology, EPA has proposed an effluent limit for total dissolved solids, which is a category of pollutants that includes bromides, of 24 mg TDS per liter.

Bromides in particular pose serious public health and public financial impacts when discharged upstream from public water system intakes. Bromide discharges "upstream from a drinking water intake has been associated with the formation of trihalomethanes, also known as THMs, when it is exposed to disinfectant processes in water treatment plants."[248] As described above and in EPA's Environmental Assessment, these disinfection by-products have been linked to bladder and other cancers.

As comprehensively evaluated in the attached report of Dr. Jeanne vanBriesen, Appendix B, the disinfection by-products created when bromide is present in the source water are especially harmful.[249] Because over 200 million Americans are served by water systems employing disinfection methods, even small risks are significant.[250] However, because disinfection by-products are regulated in the drinking water system are monitored and regulated as a whole—not making a distinction between chlorinated and brominated byproducts—increasing bromide in the source water creates increased and often undetected risks to the population served by a drinking water treatment system.[251] Disinfection by-products are extremely difficult and costly to remove from the public water supply.[252] A study of the water supply for 23 million Californians estimated costs of up to $90 million to treat disinfection by-products based on current water

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[246] *Id.* at 13.
[247] *Id.*
[248] 78 Fed. Reg. at 34,477.
[249] vanBriesen Report, Appendix B, at 17-18.
[250] *Id.* at 17.
[251] *Id.* at 18.
[252] *Id.* at 20-22.

quality and drinking water standards.[253] As those drinking water standards are updated to reflect mounting evidence about the harms of brominated disinfection byproducts, and as source water quality continues to decline, it is estimated that those costs could rise to $1 billion.[254]

As discussed in the attached report by Synapse Energy Economics, Inc., Appendix A, because EPA did not attempt to quantify how reduced bromide discharges would reduce water treatment costs for often cash-strapped water supply systems, this key societal and public health benefit was essentially ignored in EPA's decision-making process about BAT for FGD wastewater.[255] Thus, EPA has underestimated both the public health and public financial implications of failing to control bromide levels in FGD wastewater. EPA's benefit-cost analysis for Option 5 is therefore skewed. Moreover, because EPA does not account for brominated disinfection byproducts as part of the toxic-weighted pound equivalent value that is critical to the cost-effectiveness analysis, the true cost-effectiveness of mechanical evaporation is seriously understated.

Drinking water utilities are concerned about escalating levels of bromide in the water supply, as those elevated levels has made it increasingly difficult for them to meet Safe Drinking Water Act requirements for trihalomethanes.[256] Indeed, even at Belews Creek, which operates a biological treatment system, the permitting authority is concerned about bromides in the FGD wastewater. The plant's 2012 NPDES permit requires, for the first time, monthly monitoring for bromides at the outfall from an ash settling pond that receives the effluent from the FGD treatment system.[257] The permit contains a separate requirement to evaluate bromide reduction technologies for these discharges and to coordinate with downstream water systems.[258] If EPA does not select mechanical evaporation as BAT, it will simply be shifting the cost of addressing the bromides problem from the well-funded electric generating sector onto resource-limited public water systems.

5. *The effluent limits based on mechanical evaporation are reasonable.*

EPA's effluent standards for mechanical evaporation are based on data from the Enel's Federico II plant in Brindisi, Italy.[259] These limits are based on a rigorous and well-documented sampling analysis at that plant.[260] The system at Brindisi produces two separate wastewater streams: a distillate from the brine concentrator and a condensate from the crystallizer. EPA based its effluent limits on the more concentrated of the two waste streams—the crystallizer condensate. Because most plants operating these systems will combine these waste streams prior to discharge or reuse in the plant, EPA's decision to base the limits on the more concentrated waste stream

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[253] *Id.* at 21.
[254] *Id.*
[255] Instead, EPA "recommends that permitting authorities consider the potential for bromide discharges to adversely impact drinking water intakes when determining whether additional water quality-based effluent limits may be warranted." 78 Fed. Reg. at 34,473, 34,477. But EPA may not defer to the WQBEL process its responsibility to regulate, under Section 1311(b)(2)(A), pollutants found in these waste streams.
[256] EA at 3-11.
[257] 2012 NPDES Permit for Belews Creek Steam Station, NC0024406, at p.4.
[258] *Id.* at Condition A.(14), p.9.
[259] TDD at 13-19.
[260] *See* EPA-HQ-OW-2009-0819-1792.

provide an extra margin for compliance.[261] Therefore, these limits should be readily achievable at plants operating a well-managed mechanical evaporation system.

Other than having a much more advanced wastewater treatment system, the Brindisi plant is similar to many coal plants in the United States. The plant was built in 1993 and has four units that are scrubbed by a limestone forced oxidation system.[262] The plant burns a blend of low sulfur and bituminous coal, has SCR installed for NOx control on all four units, a fabric filter on Unit 3, and ESPs on the other units.[263] Therefore, the record supports EPA's conclusion that these limits could be achieved by plants in the United States operating a similar system, comprising pre-treatment, vapor compression, and crystallization.

B. CHEMICAL PRECIPITATION PLUS BIOLOGICAL TREATMENT IS A SECOND-BEST ALTERNATIVE FOR FGD.

EPA's technology basis for Options 2, 4, 4a, and 4 is chemical precipitation followed by biological treatment. This combination of technology achieves substantial reductions in discharges of toxic mercury and arsenic—through the chemical precipitation process—and reductions in selenium and nitrate/nitrate levels through the biological treatment system. While it does not address bromides, boron, or TDS, it achieves the best removal, second to mechanical evaporation. We will sometimes refer to this treatment technology as simply "biological treatment."

None of the BAT factors rules out this combination of technologies and, indeed, compel them if there is some legitimate basis for rejecting mechanical evaporation that EPA has yet to identify. Chemical precipitation plus biological treatment is technologically available and economically achievable for FGD wastewaters. As discussed below, it is also technologically available and economically achievable for treatment of coal combustion landfill leachate, which is similar in character to FGD wastewater.[264]

1. Chemical precipitation plus biological treatment is technologically available

Chemical precipitation plus biological treatment is a very well established technology to treat FGD wastewater.[265] There are already at least six full-scale ABMet biological treatment systems in the United States, in addition to nine ongoing pilot tests.[266] The largest of these is the system at Progress Energy's Roxboro plant, which treats up to 1,400 gallons per minute.[267]

[261] TDD at 13-19 to 13-20.
[262] *Id.* At 3-13, 13-5; ENEL Site Visit Notes, EPA-HQ-OW-2009-0819-1795.
[263] EPA-HQ-OW-2009-0819-1791, at 2-1.
[264] TDD at 7-39.
[265] This process has also been used to reduce selenium and other metals in many other industries, including: drainage water from irrigated agriculture, mining wastewater, metals processing wastewaters. and oil refinery wastewaters. Jenkins FGD Report, Appendix C, at 4.
[266] *See* ERG Memo, Status of Biological Treatment Systems to Remove Selenium (April 19, 2013), EPA-HQ-OW-2009-0819-2127.
[267] Blankenship, Steve, "Bugs" Used to Treat FGD Wastewater, Power Engineering, Dec. 20, 2010, EPA-HQ-OW-2009-0819-1233.

Despite this record of experience, industry has raised concerns that biological treatment systems are too vulnerable to fluctuations in influent characteristics. In the proposed rule, EPA notes "industry concerns with the feasibility of biological treatment at some power plants [, s]pecifically . . . that the efficacy of these systems is unpredictable, and is subject to temperature changes, high chloride concentrations, and high oxidation reduction potential in the absorber (that may kill the treatment bacteria)."[268]

We agree with EPA that the available data do not support these assertions. As the attached report of Dr. David Jenkins discusses, although the biological system functions most effectively with certain influent characteristics, variations in influent characteristics can be accommodated by adequate equalization, monitoring and instrumentation controls. The plants currently operating these systems have already developed approaches to deal with variability in the wastewater characteristics. For example, the Roxboro plant has a 250 million gallon impoundment that can store up to 30 days of blowdown capacity and serves to "equalize the blowdown to mitigate any fluctuations in the chemistry of the stream."[269] In addition, when the system was being installed at Allen, Duke Energy learned from some of the early experience at Belews that additional ORP and pH probes were needed for proper operation.[270]

While the wastewater purged from the scrubber may be variable, there are many treatment steps and opportunities for equalization, monitoring and adjustment before that wastewater enters the bioreactor.[271] Wastewater leaving the scrubber typically passes through a gypsum separation system (like a hydrocyclone), then various equalization and precipitation tanks. At each of these stages, the water cools, is mixed with earlier and later purges from the FGD system, and can be monitored and adjusted.[272]

Steam EGUs are sophisticated, well-controlled and well-monitored systems—it is unrealistic to assert that the wastewater entering the bioreactor would be subject to unpredictable and unmanageable variations. Plant managers are accustomed to monitoring processes and operations to ensure compliance with stringent air pollution control measures, and that expertise can be employed to ensure that water permit limits are met as well. Moreover, the air pollution controls systems generating these wastewaters also have operational limitations. Although the ABMet system tolerates up to only 20,000 ppm chloride,[273] FGD scrubbers themselves are also not generally constructed to withstand anything higher than 20,000 ppm chlorides.[274] An increase in chloride levels above what the ABMet system can handle would therefore be the result of poor plant operation, not a regularly occurring plant process that would need to be modified to accommodate the ABMet system.

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[268] 78 Fed. Reg. at 34,470.
[269] Sonstegard et al., Full Scale Operation of GE ABMet Biological Technology for the Removal of Selenium from FGD Wastewaters, EPA-HQ-OW-2009-0819-2079, at 4.
[270] Jenkins Report, Appendix C, at 9.
[271] *Id.* at 7.
[272] *Id.*
[273] Sonstegard, Full Scale Operation, EPA-HQ-OW-2009-0819-2079, at 3.
[274] TDD at 6-2.

EPA has established biological treatment systems as BAT in other industries, illustrating that the systems are not inherently unpredictable or unstable and that their use has proved appropriate as an industry-wide standard.[275]

a. Well-managed biological systems are resilient to a wide range of influent conditions.

The ABMet system has been designed to handle the highly concentrated FGD wastewater. The bacteria used to seed the bioreactor "have been isolated from previously-contaminated sites and chosen specifically for use in FGD systems because of their hardiness in the extreme water chemistry as well as for their proven efficiency for selenium respiration and reduction." [276] According to Duke Energy's Bill Kennedy, the activated carbon inside the ABMet reactor provides a physical structure to which the bacteria can attach; this structure "allows them to respond to upsets. If something changes in the system, they're actually protected down inside the carbon structure, and the bacteria will not be washed out even in extreme conditions."[277] According to the operators of the Allen system, steady-state can be re-achieved within 1 to 2 residence times of a significant variation.[278]

- <u>Oxidation-Reduction Potential:</u> One parameter about which EPA seeks additional information is the impact of ORP of the wastewater entering the biological system. Oxidation-reduction potential is the tendency of a chemical species to acquire electrons and be "reduced." This is an important factor for the functioning of the biological reactor, because that reactor works by reducing oxidized forms of selenium (e.g., selenate, selenite), and also oxidized forms of nitrogen such as nitrate and nitrite to their elemental forms. These oxidized compounds then form "nanospheres of granulated elemental selenium which accumulate in and around the bacterial cells" within the activated carbon matrix.[279] The reduced nitrogen forms a gas, which along with other organic gases is removed from the system by "burping" on a regular basis.[280]

  The wastewater entering the bioreactor has a positive ORP of around +200 or +300 mV.[281] If the ORP of the wastewater entering the reactor is too high, then not all of the metals, nitrates, and nitrites would be removed. Thus, careful control of the influent ORP

[275] *See, e.g.*, 42 Fed. Reg. 1398-426 (1977) (setting standard based on activated sludge treatment for pulp and paper industry); 39 Fed. Reg. 7894 (Feb. 28, 1974) (setting standard for meatpacking industry based on aerobic and anaerobic lagoons); 65 Fed. Reg. 81,242, 81,269-70 (Dec. 22, 2000) (setting organic pollutant standard for centralized waste treatment industry based on sequential batch reactor); 69 Fed. Reg. 54476 (Sept. 8, 2004) (setting total nitrogen standard for meat producing facilities based on biological treatment, nitrification, partial denitrification, and disinfection); 52 Fed. Reg. 42,522 (Nov. 5, 1987) (setting standard for sources in the Organic Chemicals, Plastics, and Synthetic Fibers (OCPSF) industrial category based on biological treatment usually involving activated sludge or aerated lagoons); 63 Fed. Reg. 50,388 (Sept. 21, 1998) (setting organic pollutant standard for pharmaceutical manufacturing industry based on advanced biological treatment).
[276] Sonstegard et al., "ABMet: Setting the Standard for Selenium Removal," EPA-HQ-OW-2009-0819-1233, at 2.
[277] Blankenship, Steve, "Bugs" Used to Treat FGD Wastewater, Power Engineering, Dec. 20, 2010, EPA-HQ-OW-2009-0819-1233, at 5.
[278] Final Allen Site Visit Notes, EPA-HQ-OW-2009-0819-0598, at 12.
[279] TDD at 7-12; Sonstegard et al., Full Scale Operation, EPA-HQ-OW-2009-0819-2079, at 4.
[280] TDD at 7-12.
[281] Sonstegard, Full Scale Operation, EPA-HQ-OW-2009-0819-2079, at 4.

is essential. The ABMet system achieves this by "feeding a proprietary molasses-based nutrient lend into the reactors as a carbon source for the bacteria."[282] Dr. Jenkins similarly notes that "Process control is necessary to maintain the correct ORP conditions for Se removal. This requires the installation of ORP sensor and control instrumentation on each of the individual anaerobic treatment units. The ORP sensor signal regulates the molasses dosing rate which in turn decreases (more molasses added) or increases (less molasses added) the ORP."[283]

- Temperature: EPA's record and other available evidence shows that the ABMet system can operate effectively in all climates. The ABMet system is guaranteed to perform between approximately 40ºF and 105ºF.[284] EPA has already accounted for climatic difference by including the cost of a heat exchanger in the cost estimate for plants in the southern United States.[285] However, heat exchangers may not be necessary where the plant can use an existing FGD wastewater settling pond to cool the blowdown. The Roxboro plant in North Carolina, which has been operating a biological treatment system for FGD water since 2008, uses a 250 million gallon settling pond to cool the FGD blowdown, which exits the gypsum dewatering step at a temperature of 105°F.[286]

  Data show that the ABMet biological system was resilient in a range of temperatures.[287] At two plants that allowed wastewater to equalize to ambient outdoor temperature before entering the ABMet system, summer influent temperatures as high as 95 °F and winter temperatures as low as 42 °F. Despite this variation in temperature, "effluent results . . . remained constant throughout the year."[288]

  Biological activity slows at lower temperatures, but the biological community remains intact.[289] When the ABMet system was starting up at the Roxboro plant in February 2008, the water in the FGD settling pond was only 50 ºF, 10 ºF lower than the design value.[290] The operator compensated for this by running the wastewater through a heated recirculation loop to bring the temperature up to 80 ºF. Ultimately, however, the system acclimated to lower temperatures and raw feed water could be introduced without supplemental heating.[291] According to the inventor of ABMet, Tim Pickett, "selenium

[282] *Id.* at 5. *See also* Jenkins FGD Report, Appendix C.
[283] Jenkins FGD Report, Appendix C, at 6-7. Sonstegard et al., also state that "accurate, factory certified ORP probes are critical." Full Scale Operation, EPA-HQ-OW-2009-0819-2079, at 7.
[284] Jenkins FGD Report, Appendix C, at 3; see also Sonstegard, ABMet Biological Selenium Removal from FGD Wastewater, EPA-HQ-OW-2009-0819-1232, at 3-4.
[285] TDD at 9-23.
[286] Sonstegard et al., Full Scale Operation of GE ABMet Biological Technology for the Removal of Selenium from FGD Wastewaters, EPA-HQ-OW-2009-0819-2079.
[287] Sonstegard et al., Setting the Standard for Selenium Removal, Docket No., EPA-HQ-OW-2009-0819-1233, at 2-6.
[288] *Id.* at 5.
[289] *See* Jenkins Report.
[290] Sonstegard et al., Full Scale Operation, EPA-HQ-OW-2009-0819-2079, at 7.
[291] *Id.*

removal is achieved in a matter of hours."[292] Thus, the residence time in the bioreactor is likely short enough that accommodations will not need to be made for low temperatures in all but the most extreme climates.[293]

The record supports a conclusion that ambient temperature concerns do not render ABMet technologically infeasible.

b. Biological reactors can operate effectively with intermittent wastewater streams.

The record shows that biological reactors are compatible with the sometimes intermittent nature of the FGD wastewater flows. The FGD wastewater flow may be intermittent if the plant operates on a cycling basis, or due to planned and unplanned outages. EPA's record shows that even in the event of an unplanned outage, the biological treatment system can be maintained without any serious issues.[294] At one plant where what was thought to be a temporary outage evolved into a 48-day shutdown, the plant responded by periodically (every four days), running process water through the bioreactor, along with a dose of nutrients, to prevent the matrix from becoming dormant.[295] The period also allowed time for flushing and backwash of the system. After the system was restarted, it was immediately capable of achieving extremely low levels of selenium in effluent, close to 2 ug/L.[296] This event demonstrated the resiliency of the bioreactor in the event of a longer-term shutdown, when experienced staff are available to maintain the system. Likewise, during a pilot test at Duke Energy's Marshall plant, it was confirmed that station upsets and shutdown "had no significant impacts on performance."[297]

The plant that experienced the extended unplanned outage is designated as a cycling facility, meaning that it has frequent short-term shutdowns in response to changes in demand. But as its operators have found, the cycling nature of the plant has not caused any problems in operation or efficacy of the bioreactor.[298] Duke Energy's Allen plant is a cycling, rather than baseload plant, and the plant's operators have developed procedures to maintain the biological system during these periodic shutdowns.[299] If the plant has advance notice of a shutdown, it can reserve FGD purge water in the equalization system and operate the system at reduced flow rate just prior to and during the shutdown. If the plant does not have notice of a short shutdown, it will run service water and nutrients through the reactor. During a three week shutdown, the plant simply

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[292] Blankenship, Steve, "Bugs" Used to Treat FGD Wastewater, Power Engineering, Dec. 20, 2010, EPA-HQ-OW-2009-0819-1233. *See also* Sonstegard et al., ABMet: Setting the Standard for Selenium Removal, EPA-HQ-OW-2009-0819-1233, at 1 (ABMet designed to remove selenium in a two-to-sixteen hour empty bed contact time).
[293] *See Weyerhaeuser Co. v. Costle*, 590 F.2d 1011, 1055 & n.73 (D.C. Cir. 1978) (finding that EPA had properly considered the impact of colder ambient temperature in finding a biological treatment system to be BAT, where EPA found that waste treatment would occur before the influent had cooled significantly, due to the 6-8 hour residence time of the system); *see also Am. Meat Inst. v. E.P.A.*, 526 F.2d 442, 455 (7th Cir. 1975) (finding firm record support for EPA's conclusion on the effect of cold weather on the efficiency of the anaerobic lagoon).
[294] Sonstegard et al., Setting the Standard, EPA-HQ-OW-2009-0819-1233, at 6.
[295] *Id.*
[296] *Id.* at 6-7.
[297] Blankenship, EPA-HQ-OW-2009-0819-1233, at 4.
[298] Sonstegard et al., Setting the Standard, EPA-HQ-OW-2009-0819-1233, at 7.
[299] *See* Final Site Notes for Allen, EPA-HQ-OW-2009-0819-0598, at 12.

left idle water in the system, and the bioreactor returned to typical performance within 24 hours of restart.[300]

For similar reasons, the intermittent nature of landfill leachate streams would not be problematic for operation of the biological treatment system, assuming proper monitoring and storage capacity. *See infra* Section VI.

2. Chemical precipitation plus biological treatment is economically achievable.

EPA has estimated that the total capital cost for the 116 plants that would need to retrofit with biological treatment is $2.5 billion, and that total O&M costs across these same plants would be $257 million. The data show that, considering the size and revenues of this industry, it can reasonably bear these costs.

Option 3 would increase annual costs by approximately 0.6% and increase variable production costs by 0.5%, and would result in no change in generating capacity.[301] Option 4 would increase annual costs by 1.4%, variable production costs by 1%, would cause a 0.1% increase in unit retirements.[302] Even if all of the costs of either Option 3 or Option 4 were attributed to biological treatment of FGD wastewater – which they are not, making it a highly conservative assumption – the costs could still be reasonably borne by industry.

Although EPA did not directly evaluate the cost-to-revenue ratios for biological treatment standing alone, it did so for the options including a biological treatment component—Options 2, 3, and 4—and the results confirm that this technology is affordable. Even the most expensive of these options, Option 4, would impose annualized compliance costs of more than 3 percent of revenue for only 48 out of 1,079 plants.[303] Nearly 800 plants would experience no costs, 111 plants would experience costs of less than 1 percent of annual revenues, and 117 plants would experiences costs of between 1 and 3 percent of annual revenues.[304]

The baseline cost-to-revenue analysis assumes—unrealistically—that utilities would pass on none of the costs to their customers. EPA did conduct a sensitivity analysis to account for the likelihood that 50% of these costs could be passed through to consumers; that sensitivity analysis illustrates the affordability even more starkly. For Option 3, assuming that plants could pass through 50 percent of their costs to consumers, only three plants would see a cost-to-revenue impact that is greater than 3 percent. For Option 4, that number increases to only ten plants.[305] As biological treatment is a part of each of these options, it follows that it too, is economically achievable for the industry as a whole.

As we explain elsewhere in these comments, the Clean Water Act does not authorize EPA to use cost-effectiveness as the sole or primary basis of a BAT determination; the correct legal standard

[300] *Id.*
[301] 78 Fed. Reg. at 34,498.
[302] *Id.*
[303] RIA at Table 4-1.
[304] *Id.*
[305] RIA, Appendix B, at Table B-2.

is whether costs can be borne by the industry as a whole.[306] However, even if cost-effectiveness were the correct test, EPA must conclude that a biological treatment standard for FGD waste water is cost-effective. The cost of this treatment option is only $60 per TWPE removed, which is in the middle of the range for technology options that EPA considered to be preferred.[307] This is also well within the cost-effectiveness values for BAT options selected by EPA in previous rulemakings.[308] Although we do not agree that cost-effectiveness should be given significant weight in the BAT determination or that EPA's preferred range of dollars per TWPE removed is appropriate, biological treatment of FGD wastewater is clearly cost-effective applying EPA's preferred methodology.

Moreover, the industry-wide cost estimate is likely an overestimate because there are numerous other biological treatment technologies in development, pilot-testing, and operation that may have lower costs.[309] For example, anaerobic suspended growth reactors that target removal of selenium and other metals was commissioned at one plant in January 2012 following successful pilot testing.[310] In addition, CH2MHill has developed a system configured as a fluidized bed reactor that removes selenium from wastewater through a similar biological mechanism as ABMet, which may cost only one-third as much as an ABMet system.[311] The same company is developing "two additional configurations of biological treatment systems for selenium removal: a lined earthen basin-based FBR system; and a "biochemical reactor" process, a passive system which also employs anoxic/anaerobic reactions to reduce selenium," both of which will cost even less than the fluidized bed reactor.[312]

EPA's industry-wide cost estimate also does not account for how the closure of FGD wastewater settling ponds will make space available for on-site landfills, which would dramatically reduce the operating costs (transportation and fuel) compared to off-site disposal.

EPA must conclude that biological treatment of FGD wastewaters is economically achievable for the industry.

3. *The other BAT factors do not alter the conclusion that biological treatment is technologically and economically achievable.*

None of the other factors that EPA has considered under 33 U.S.C. § 1314(b)(2)(B) counsel against selecting biological treatment as BAT. EPA's record supports that the age of a

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[306] *See infra* Section IX.
[307] TDD at 8-34.
[308] *See* RIA at D-8.
[309] *See* Synapse Report, Appendix A, at 18-20 (re: overestimation being a chronic problem). Dr. Jenkins cites to an upflow fluidized bed system developed by Envirogen Technologies, that has been demonstrated to reduce selenium levels in mining wastewater to under 5 ug/L. Jenkins FGD Report, Appendix C, at 5.
[310] *See* TDD at 7-12 ("One plant has pilot tested another type of anoxic/anaerobic biological treatment system that consists of suspended growth flow-through bioreactors instead of fixed-film bioreactors. Both designs share the fundamental processes that lead to nitrification/denitrification and reduction of metals in anoxic and anaerobic environments. Based on the results of the pilot test, in January 2012, the plant commissioned a full-scale suspended growth bioreactor system to treat FGD wastewater.")
[311] John Koon Rebuttal to the Expert Report of Thomas E. Higgins, In re: Bull Run NPDES permit, Exhibit FGD-19, at 15-16.
[312] *Id.*

generating unit does not affect the feasibility of biological treatment. Because the FGD wastewater is transferred to a pond or wastewater treatment system and treated in a distinct system, the plant's age is irrelevant.[313] Over a dozen of the plants that operate chemical precipitation systems are at least 40 years old, and all five plants operating biological treatment systems are at least 20 years old, while one is a 50 years old.[314]

Nor does the size of a given facility affect the feasibility of biological treatment. The ABMet reactor system can be scaled upward to treat the FGD blowdown from multiple units or larger units. EPA analyzed unit-level annualized costs for FGD wastewater treatment compared to unit capacity, and the data show no discernible trends as the capacity of a unit increases.[315] This outcome is sensible, because the cost to treat FGD wastewater using a biological system depends in large part on the FGD blowdown rate, with is more strongly related to scrubber type and construction, coal type, and permitted SO_2 emission limits.

For the vast majority of plants, available space will not be not a constraint for installation of the chemical precipitation plus biological treatment system. The chemical precipitation and biological treatment option involves, in a physical sense, a series of connected tanks. This system is unlike lagoon-based aerobic biological systems or constructed wetlands which may have a larger footprint.[316] At the Allen plant, five acres were set aside for the ABMet system, which ended up using only half of that space.[317] For the Roxboro plant, which has the largest flow of any scrubber treated with ABMet,[318] the footprint is less than one acre.[319] Considerable space is already used at these plant areas for the massive impoundments currently used to "treat" the wastewater prior to discharge. A single surface impoundment can occupy up to 300 acres of the plant site.[320] Closure of these ponds would free up considerable space for the relatively small tank system needed for the biological treatment option. Many coal-burning power plants are located in rural, undeveloped areas, and could readily purchase a few acres of adjacent land if necessary. Moreover, the biological treatment system need not be located in any particular area on the plant site—it can be relatively remote from the FGD system, so long as there is a clear path for a pipe or conduit to transmit the FGD wastewater to the initial equalization tank.[321]

The minimal non-water quality impacts of chemical precipitation plus biological treatment do not weigh against their selection as BAT. EPA has estimated that the "energy increases associated with Regulatory Option 3 will be less than eight thousandths of a percent (0.008%) of the total electricity generated by all electric power plants."[322] Although the chemical precipitation and biological treatment backwash will create additional solid waste, EPA estimates

[313] EPA-HQ-OW-2009-0819-2258, at 5-6.
[314] *Id.* at 6.
[315] *See* ERG Non-CBI Subcategorization Memo, EPA-HQ-OW-2009-0819-2258, at Figures 5 & 6.
[316] *See, e.g.*, *Ass'n of Pac. Fisheries v. E.P.A.*, 615 F.2d 794, 819-20 (9th Cir. 1980) (noting large land area required for aerated lagoon-based treatment system).
[317] Blankenship, Docket No. EPA-HQ-OW-2009-0819-1233, at 3.
[318] *Id.*
[319] Sonstegard, Full Scale Operation, EPA-HQ-OW-2009-0819-2079, at 3.
[320] TDD at 8-6.
[321] *See* ERG Non-CBI Subcategorization Memo, EPA-HQ-OW-2009-0819-2258, at 5-6.
[322] EPA-HQ-OW-2009-0819-2133, at 6. Because Option 3 includes biological treatment for FGD wastewater, but not dry handling for bottom ash, the estimated incremental energy usage for this option is a better approximation of the impacts associated with biological treatment.

that the "increases associated with Regulatory Option 3 will be less than 0.001 percent of the total solid waste generated by all electric power plants."[323] EPA also found that recycling water at five high-flow FGD treatment systems, already economical because it reduces the size of the needed biological treatment system, would reduce freshwater intake by 7.7 million gallons per day.[324] These water savings are likely an underestimate, as they do not account for the reuse of post-treatment FGD wastewater in other plant processes, so long as the FGD wastewater meets the effluent limits before it is mixed with any other waters. Thus, EPA's record fully supports a conclusion that the non-water environmental quality impacts support a determination that biological treatment is BAT for FGD wastewater.

4. *EPA's proposed effluent limits for the biological treatment BAT option can be reliably achieved across the industry*

EPA gathered extensive monitoring data about the performance of the systems at two plants: Belews Creek and Allen, because these were the two plants that had been operating at least six months and achieved steady state, according to their operators. Based on these data, EPA has proposed limits for arsenic, mercury, selenium, and nitrates/nitrites. EPA's limits for mercury and arsenic are based on the performance of a chemical precipitation system employing both hydroxide and polysulfide treatment, while the selenium and nitrate/nitrite limits are based on the biological treatment system.

All of these effluent limits proposed by EPA are supported by the record. In fact, the record would support setting mercury and arsenic limits even lower based on the additional reductions that occur in the biological treatment system.

On behalf of the Sierra Club, Dr. David Jenkins reviewed the data used by EPA to set these proposed standards. Dr. Jenkins was also able to obtain influent and effluent data for selenium and mercury for a third plant operating the ABMet system, which the vendor identified simply as the "NE USA" plant. According to the vendor, the plant uses both hydroxide and polysulfide chemical precipitation prior to the biological treatment system, which means that this system represents more completely the treatment technology proposed as BAT than the Allen and Belews plants.

We believe that the data obtained from the vendor is for the American Electric Power Mountaineer plant in West Virginia. The vendor identifies that plant as a single-boiler 1300 MW facility, and the system became operational in late 2011.[325] Both of these relatively unique facts match the Mountaineer plant in the record.[326] Another critical fact is that the vendor reports that the ABMet system handles combustion waste landfill leachate, which is true of the Mountaineer system as well.[327] This fact is highly relevant for EPA's BAT determination regarding leachate, as is discussed in detail further below.

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[323] *Id.* at 13.
[324] *Id.* at 15.
[325] Jay Harwood, Making the Change: Meeting EPA Effluent Limitation Guidelines, May 23, 2013, at slides 23-24.
[326] *See* Email to TJ Finseth from AEP, Docket No. EPA-HQ-OW-2009-0819-0577, stating that the ABMet system at Mountaineer started up on Nov. 11, 2011, and achieved steady state on February 11, 2012.
[327] *See* HDR, Inc., Biological Treatment for Power Generation, June 11, 2013, at Slide 16; *see also* ERG Memo, Status of Biological Treatment Systems to Remove Selenium (April 19, 2013), EPA-HQ-OW-2009-0819-2127.

As discussed in the report of Dr. David Jenkins, Appendix C, the effluent data from Belews and Allen plants, as well as those from a third plant, show that the ABMet system can reliably meet the selenium and mercury limits set by EPA, and that the ABMet system can achieve mercury reductions even greater than those achieved by the two-stage chemical precipitation system.

a. EPA's proposed selenium limits can be met by the biological treatment system under a range of influent conditions.

Based on Dr. Jenkins' analysis of the data from the Mountaineer plant, "the ABMet® unit consistently produced an effluent with a total Se level below 7.2 ppb and with many values in the 1-2 ppb range (Figures 5 and 6) making it fully compliant with the EPA's proposed daily maximum and monthly average total Se limitations."[328] As Dr. Jenkins concludes, once the ABMet system at the Allen plant was fully acclimated, it was able to handle significant fluctuations in the influent total selenium levels, and still meet the proposed selenium effluent limits.[329]

Data from all three plants show that meeting the selenium limits set by EPA can be achieved, after an adequate start up and commissioning period, so long as tight process control is maintained, there is adequate sensing and control capabilities, and the system "provide[s] adequate equalization capacity within and/or between the first-stage chemical precipitation process and the biological treatment stage."[330] Monitoring of the selenium levels at the effluent from the chemical precipitation stage is also critical.[331]

b. EPA's mercury limits can be met by the biological system following only hydroxide precipitation.

EPA's mercury limits for the biological treatment option are well supported by the record. Because those limits are based on the performance of the chemical precipitation system, and do not account for additional removals of mercury in the biological system, even lower mercury limits could be established.

EPA acknowledged this additional metals removal in the biological treatment system,[332] finding that "the biological treatment stage provides pollutant removals for arsenic and mercury (and other pollutants of concern with similar removal mechanisms) in addition to the pollutant removals that occur in the chemical precipitation stage of the biological treatment technology option . . . . Thus, plants employing and optimally operating all components of the biological treatment technology option (including adding organosulfide to achieve sulfide precipitation) should achieve pollutant removals for arsenic and mercury (and other pollutants with similar

[328] Jenkins FGD Report, Appendix C, at 9.
[329] *Id.* at 8.
[330] *Id.* at 10. EPA's exclusion of data during start-up, commissioning, and upsets for the Allen plant was justified. Dr. Jenkins concludes that based on the Allen system's ability to handle subsequent spikes in influent selenium, it was justified for EPA to omit earlier selenium exceedences that corresponded to influent selenium spikes, on the basis that the system was still in a start-up or commissioning phase. *Id.* at 8.
[331] *Id.*
[332] 78 Fed. Reg. at 34,473.

removal mechanisms) that are equal to or even greater than the removals based on chemical precipitation technology."[333]

Dr. Jenkins' analysis confirms EPA's findings for mercury:[334] "in all of the ABMet® plants evaluated the biological stage of the "Chemical Precipitation and Biological Treatment" provided additional Hg removal over that obtained by the chemical precipitation step (Figures 12-14) both when the precipitation step employed hydroxide only and when it employed hydroxide plus polysulfide."[335]

Dr. Jenkins concludes that the "anaerobic biological system effluent total Hg concentration seems to be proportional to the biological system influent total Hg over an influent total Hg range from approximately 1000 ppt to approximately 20 ppt."[336] Thus, if the effluent from the chemical treatment system is compliant with the limits EPA set for mercury based on that technology (242 ppt daily maximum and 119 ppt monthly average), then even lower levels would be expected in the effluent.

c. The biological treatment option can meet EPA's proposed effluent limits across a range of operating conditions.

Industry has expressed concerns that EPA has based its limits for the biological treatment option only on plants burning eastern bituminous coal, and that these results may not be achievable at plants burning other types of coal. This concern overlooks is that wet FGD systems are most likely to be used at plants burning bituminous coal. According to EPA and EIA data, over 70% of the nation's wet-scrubbed generating capacity is at plants that burn bituminous coal.[337] This is because bituminous coal has high sulfur levels, and therefore requires the greater sulfur dioxide removal rates of a wet scrubber, as compared to a dry scrubber. Plants burning sub-bituminous coals are more likely to control SO_2 using a dry scrubber or dry sorbent injection, if any SO_2 emission controls are needed at all.[338] Plants burning a lower-sulfur, lower-chlorine coal will have FGD wastewater purges that are lower in concentrations of metals and other constituents (such as chlorides) that would affect the bioreactor.

Nor does the record support that plants operating different types of scrubbers will have difficulty meeting these standards. The effluent from forced oxidation scrubbers, like those at Belews Creek and Allen, contains a higher percentage of selenate as compared to selenite.[339] Selenate is harder to remove than selenite—therefore evaluating data from forced oxidation scrubbers

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[333] TDD at 13-26.
[334] Dr. Jenkins found that the presence of non-detects in both the influent to and effluent from the biological treatment system prevented a similar analysis regarding arsenic.
[335] Jenkins FGD Report, Appendix C, at 11.
[336] *Id.* at 12.
[337] *See* EPA 2009 Final Detailed Study Report, EPA-HQ-OW-2009-0819-0387, at Table 4-2. To the extent that plants switch to PRB coal, they would be able to use dry scrubbers and eliminate the FGD wastewater stream entirely.
[338] Lindsay Morris, The Ins and Outs of SO2 Control, Power Engineering, June 1, 2012, available at http://www.power-eng.com/articles/print/volume-116/issue-6/features/the-ins-and-outs-of-so2-control.html.
[339] TDD at 6-2 to 6-3.

provides a stringent test of the capability of the ABMet system.[340] Moreover, as EPA notes, most plants operating natural and inhibited oxidation systems do not discharge FGD wastewater because they completely recycle or passively evaporate the water.[341] Therefore, the record supports EPA's conclusion that plants operating natural and inhibited oxidation scrubber systems will not have difficulty complying with the biological treatment option.

C. CHEMICAL PRECIPITATION IS NOT BAT FOR FGD WASTE.

EPA has proposed, under Option 1, to establish effluent limits based on chemical precipitation of FGD wastewater. However, EPA properly has not identified Option 1 as a preferred option, because the record does not support a conclusion that chemical precipitation is BAT for FGD wastewater. BAT-based numeric effluent limits "shall require the elimination of discharges of all pollutants if the Administrator finds, on the basis of information available to him ... that such elimination is technologically and economically achievable."[342] As the record shows, chemical precipitation "is not effective at removing many of the pollutants of concern in FGD wastewater, including selenium, nitrogen compounds, and certain metals that contribute to high concentrations of total dissolved solids in FGD wastewater (e.g., bromides, boron)."[343] As described above, *supra* Section I, selenium is highly toxic to aquatic organisms. Nitrates in drinking water are especially dangerous for children under the age of six, and are the cause of methemoglobinemia, or "blue baby syndrome."[344] Chemical precipitation does nothing to address either of these pollutants. Even for the pollutants that chemical precipitation can treat, such as mercury and arsenic, adding biological treatment achieves even greater reduction.[345]

EPA's effluent limits based on chemical precipitation also do not reflect even the best-performing precipitation systems. EPA chose to base its limits on a one-stage system, rather than a two-stage precipitation system, despite acknowledging that "two-stage chemical precipitation systems generally achieve better pollutant removals than one-stage systems."[346] The two-stage system allows the pH and other conditions to be optimized for each precipitation step.[347] The Wisconsin Energy Pleasant Prairie plant uses a two-stage system, and EPA collected effluent data from that plant as part of this rulemaking.[348] Because the BAT limits for arsenic and mercury based on chemical precipitation are transferred to the chemical precipitation plus biological treatment option, EPA's decision not to use the most effective precipitation systems as the basis for these BAT limits is means that the mercury and arsenic limits for the combined chemical and biological treatment option are also much weaker than they should be. EPA must base the mercury and arsenic limits for options involving chemical precipitation on the performance of two-stage chemical precipitation.

[340] *Id.*
[341] *Id.*
[342] 33 U.S.C. § 1311(b)(2)(A) (emphasis added).
[343] 78 Fed. Reg. at 34,473.
[344] *See* U.S. EPA, Basic Information about Nitrate in Drinking Water, http://water.epa.gov/drink/contaminants/basicinformation/nitrate.cfm (last viewed Sept. 19, 2013).
[345] *Id.*
[346] 78 Fed. Reg. at 34,487 n.62.
[347] TDD at 7-5 to 7-6.
[348] 78 Fed. Reg. at 34,487 n.62.

Ultimately, however, whatever options for chemical precipitation that EPA considers, chemical precipitation is not BAT. As explained above, the record evidence considered by EPA establishes that mechanical evaporation is BAT, and biological treatment is an available, affordable technology that is indisputably superior to chemical precipitation alone as a treatment for FGD wastewaters.

D. BPJ DETERMINATION IS AN INADEQUATE SUBSTITUTE FOR BAT-BASED ELGS.

Options 3a and 3b (for plants with less than 2,000 MW wet-scrubbed capacity) would leave effluent limits to be set on a case-by-case basis.[349] Not only is this inconsistent with the Clean Water Act, it would be disastrous for water quality, wildlife, and public health based on the states' failing record at making BAT determinations.

First and foremost, EPA has a legal requirement to set effluent limitation guidelines. The Clean Water Act states that "[i]n order to carry out the objective of this chapter there shall be achieved," "effluent limitations . . . , which shall require application of the best available technology economically achievable for such category or class, which will result in reasonable further progress toward the national goal of eliminating the discharge of all pollutants."[350] Although EPA may create subcategories among a class of point sources, where there are legitimate differences in what is technologically feasible, it must then establish BAT for those subcategories.[351] It may not fail, altogether, to establish BAT for a subset of facilities, and rely on case-by-case BAT determinations for those facilities.[352] The Clean Water Act's provision for case-by-case BAT determinations is meant as a stop-gap measure where EPA has not yet addressed a particular pollutant discharged by an industry, not as an alternative to establishing ELGs where, as here, there are adequate data and available technology to set comprehensive BAT limits.

1. *Most states lack the resources to develop BAT-based limits in discharge permits.*

The practical implications of EPA's failure to set ELGs for FGD wastewater are enormous. As detailed above, experience shows that local permitting authorities fail entirely to apply best professional judgment for determination of the best available technology for FGD wastewater and coal combustion residuals, or fail to do so with any rigor.[353] Despite the availability of economically and technologically achievable technologies to address these pollutants, and EPA's

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[349] 78 Fed. Reg. at 34,458, Table VIII-1.
[350] 33 U.S.C. § 1311; *see also supra* Section II.
[351] *Cf. Chem. Mfrs. Ass'n v. EPA*, 870 F.2d 177, 214 (5th Cir. 1989) (holding that subcategorization permissible when determining BPT limits if a group of plants cannot practicably achieve the limitations achieved by the best-performing plants).
[352] 33 U.S.C. § 1311(b)(2)(A) (mandating EPA to establish ELGs for categories of point sources).
[353] *See* Closing the Floodgates, *supra* note 5, (finding that out of 274 power plants discharging wastewater, only 86 had at least one limit on arsenic, boron, lead, mercury, cadmium, or selenium; 255 plants lacked any limits on arsenic; 235 plants lacked any limits on mercury; 232 lacked limits on selenium; and nearly 40 percent did not even require monitoring for any of these pollutants).

exhortations to permitting authorities to make case-by-case BAT determinations,[354] state permitting authorities have not fulfilled their obligations under the Clean Water Act. EPA is well aware that states have failed to establish technology-based effluent limits for these waste streams. EPA's regional offices have issued dozens of objection letters to states, noting the absence of BAT determinations for these waste streams.[355] However, few if any of these objections have resulted in undertaking of BPJ analyses much less the imposition of required BAT limits in the state's NPDES permits.

In part, the states' failure to include BAT-based limits stems from a lack of resources to make complex BAT determinations, which require the input of highly specialized engineers, chemists, and economists.[356] EPA Region 1 has cited limited resources and the difficulty of setting technology-based limits as an explanation for the significant backlog of NPDES permit renewals—some of which are 20 years overdue for renewal.[357]We have heard from numerous state permitting officials that they do not have the capacity and expertise to make BAT determinations, and that they would strongly prefer EPA to promulgate effluent limitation guidelines for steam EGUs. Case-by-case BAT determinations are also highly inefficient from the perspective of the permit applicant, and for the local communities affected by these discharges who might seek stronger permits. In our groups' experience, considerable staff time is required to evaluate, comment on, and challenge permits where the state has failed to make a proper BAT determination. It can cost $150,000 or more to pay for the technical and legal expenses necessary to evaluate BAT for a given plant and fully participate in the administrative review process. These expenses include hiring experts to investigate existing technologies and present alternative analyses regarding BAT for the waste stream affecting the public.

2. Reliance on BPJ determinations will disproportionately affect environmental justice communities.

As noted above, it is challenging and rare for environmental organizations such as the undersigned commenters to marshal the resources to comprehensively evaluate a BAT determination for a particular plant. Clearly, most impacted local communities lack these kinds of resources. Thus, a critical flaw with relying on case-by-case BPJ determinations is that BAT determinations will vary by jurisdiction and, even within a single jurisdiction, may vary depending on whether a local community or environmental organization is able to participate in the administrative process and has the resources to advocate for protective permit limits. Communities without resources to engage in the permitting process in this way are much less likely to be able to compel the permitting authority to issue a permit containing strong BAT-

[354] Memorandum from James A. Hanlon to EPA Regional Offices, National Pollutant Discharge Elimination System (NPDES) Permitting of Wastewater Discharges from Flue Gas Desulfurization (FGD) and Coal Combustion Residuals (CCR) Impoundments at Steam Electric Power Plants (June 7, 2010).
[355] *See* Compilation of EPA Regional Office Interim Objection Letter and Comments, submitted by Commenters as an exhibit to this letter.
[356] *See, e.g.*, Comments by Kansas Dept. of Health & Envt., EPA-HQ-OW-2009-0819-3922, at 6 ("States have neither the luxury nor the resources to collect and evaluate the data EPA has collected to address a handful of NPDES permits they administer. . . . Due to the ever dwindling staffing and resources available to states, EPA should be making the call regarding BAT for the FGD wastewater.").
[357] *See* Declaration of David M. Webster in Support of Opposition to Petition for a Writ of Mandamus, In re Sierra Club and Our Children's Earth Foundation (Case No. 12-1860, 1st Cir.) (Apr. 5, 2013) ¶¶ 40, 50, 63-64, & 76.

based limits. EPA should have evaluated the environmental justice implications of two of its preferred options—3a and 3b—which would fail to provide the same protection to under-resourced communities as a uniform national standard. EPA's environmental justice analysis fails to acknowledge the implications of reliance on BPJ for these groups.[358]

3. EPA's proposed exemptions will perpetuate and worsen a status quo in which states ignore their obligation to make case-by-case BAT determinations.

A common industry argument, echoed by a number of states, is that where EPA has decided not to set ELGs for a particular pollutant in a waste stream, the permitting authority is not required to make its own BAT determination for those pollutants.[359] As organizations that have challenged permits in many states, we have encountered this position from permit applicants and state officials countless times. For instance, the state of Kentucky has maintained the position that it has no obligation to undertake BAT determinations for pollutants other than those in EPA's 1982 ELGs, and was only just recently invalidated by a state lower court.[360]

If EPA adopts Options 3a or 3b, some state permitting offices may view this decision as authorizing a continuation of the status quo – i.e., that they still do not need to set TBELs for mercury, arsenic, selenium and other metals in FGD wastewater even after the issuance of the rule. In particular, EPA's indeterminate statements that biological treatment may not be affordable for some units[361] could be cited by state permitting agencies as a basis for concluding that biological treatment is not affordable for the particular facility in question, despite the fact that EPA's own analysis demonstrates its affordability, as described above. In addition, as Kansas Department of Health and the Environment has noted, EPA's decision not to establish BAT for FGD wastewater might make it difficult for the state to justify its decision to establish BAT on a case-by-case basis.[362] If EPA finalizes Options 3a or 3b—a decision that would be contrary to the Clean Water Act and not supported by the record—it must make very clear that state permitting authorities have a duty to establish BAT-based limits for arsenic, mercury, selenium, and other toxics in FGD wastewater.

4. EPA's cost estimates for options 3a and 3b exclude the costs of complying with BPJ determinations.

The primary reason that EPA reaches such a low estimate of the costs of Options 3a and 3b is that the Agency has ignored costs for the installation of BAT for FGD wastewaters based on

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[358] *See* 78 Fed. Reg. at 34,532; RIA at 10-2 to 10-5.
[359] *See, e.g.*, Arkansas Dept. of Envtl Quality, Response to Comments on NPDES Permit for Flint Creek Power Plant, at 14 (stating that the state is obligated to set limits based on the "currently effective" ELGs, and that EPA's 1982 Development Document showed the agency had considered toxic metals and deliberately chosen not to regulate them in coal combustion residual wastewaters).
[360] *See Kentucky Waterways Alliance et al. v. Energy & Environment Cabinet*, Civil Action No. 11-CI-1613 (Sept. 10, 2013).
[361] 78 Fed. Reg. at 34,470.
[362] EPA-HQ-OW-2009-0819-3922, at 6 ("[I]f EPA requires states to use BPJ to establish BAT criteria for the designated wastestream, it would be likely that if an industry decides to contest the state's determination as to what constitutes BAT for the FGD wastewater, the state will end up not only having to defend its technical, environmental, and economical determination, but will have to justify that decision in light of EPA having not made a similar determination when finalizing the proposed rule.")

case-by-case determinations.[363] EPA included costs for only 66 facilities under Option 3a, and for only 80 facilities under Option 3b,[364] which is far fewer than the 117 facilities operating wet FGD systems.[365] In other words, for facilities where BAT for the FGD wastewater would be determined through a case-by-case BPJ determination, EPA assumes there would be no cost for compliance with the Clean Water Act's BAT requirement. However, this assumption is contrary to EPA's assertion elsewhere that BPJ determinations will reflect the wide range of innovative treatments for FGD wastewater, and encourage the development of more advanced technologies.[366] Nor does the record support EPA's assumption that there would be zero costs on the ground that these plants have already installed BAT technology based on a state BPJ determination. As discussed above, states have failed to impose BAT-based limits for toxic pollutants in the vast majority of power plant permits.[367]

If states are doing proper BPJ determinations, they will arrive at BAT determinations very similar to what EPA has proposed for FGD wastewater in Options 4 and 5—at costs in line with what EPA has calculated for those Options. Instead of assuming zero cost for units exempt from the ELGs and subject only to BPJ under Options 3a and 3b, EPA should include estimated costs for treatment based on the state BPJ determinations. If EPA opts not to include such estimated costs, it is an implicit admission that states could continue to neglect their duty to impose BAT-based limits on FGD wastewater in virtually every permit they issue.

In short, a decision by EPA to defer to BPJ determinations to set effluent limits for toxic metals in FGD wastewater is contrary to the mandates of the Clean Water Act and utterly inadequate to bring about the Act's goal of eliminating water pollution. EPA must reject Options 3a and 3b.

E. BAT-BASED LIMITS MUST APPLY TO ALL COAL-BURNING POWER PLANTS WITH WET FGD SYSTEMS.

EPA's preferred Option 3b would set limits based on biological treatment only for units with a wet-scrubbed capacity of more than 2,000 MW. This threshold is not supported by the record on economic or technological grounds. Option 3b would exclude from BAT-based limits all FGD wastewater generated in the country, except for the stream at only 17 plants.[368] Thus, around 100 plants, as well as nearly every plant that adds a wet FGD system in the future, would have no limits on toxics metals in their FGD discharges.

EPA's stated rationale for the 2,000 MW threshold is as follows:

[363] *See* ERG, Methodologies for Estimating Costs and Pollutant Removals for Steam Electric ELG Regulatory Options 3a and 3b, EPA-HQ-OW-2009-0819-2145.
[364] *Id.* Tables 1-1 & 2-1. There appears to be an error in either Table 1-1 or Table 2-1, as the difference between the number of facilities affected should be 17—the number of plants with more than 2,000 MW of wet-scrubbed capacity that would be subject to the ELGs under Option 3b, but not under 3a. Instead, the difference is only 14 plants, and the public portions of the memorandum provide no explanation for the discrepancy.
[365] 78 Fed. Reg. at 34,483.
[366] *Id.* at 34,460, 34,470.
[367] *See supra* Section I.C.
[368] Docket No. EPA-HQ-OW-2009-0819-2145, at 4.

> For FGD wastewater only, EPA believes any threshold should be based on a plant level rather than a unit level because many plants currently use asingle FGD treatment systems to service multiple units. Additionally, EPA determined that wet-scrubbed capacity is an appropriate metric because it only reflects units that are generating FGD wastewater. For example, a plant could have a total plant nameplate generating capacity of 3,500 MW, but only have a wet-scrubbed capacity of 200 MW if only one of its units is wet-scrubbed. EPA is putting forth this option as a preferred option based on an assumption that these facilities are more able to achieve these limits based on economies of scale. These largest facilities will likely also be able to absorb the costs of installing and operating the chemical precipitation and anaerobic biological treatment systems on which the FGD wastewater limitations are based. For these reasons, as well as those specified above related to current innovation and treatment trends, Option 3b proposes that BAT effluent limitations for discharges of FGD wastewater would continue to be determined on a site-specific basis for units at facilities below the 2,000 MW threshold.[369]

This analysis is flawed for several reasons. First, as EPA acknowledges, a large plant could have a relatively small amount of wet-scrubbed generating capacity. Yet, EPA then looks at only the wet-scrubbed capacity of the plant to determine whether the plant is large enough to "be able to absorb the costs of installing and operating" the treatment systems. This ignores that the unscrubbed portions of a plant are generating revenue and contribute to the plant's ability to afford a wastewater treatment system.

EPA also assumes that plants with more than 2,000 MW of wet-scrubbed capacity "are more able to achieve these limits based on economies of scale." However, the record does not support a threshold based on economies of scale for biological treatment of FGD wastewater, as the cost per MW of installing and operating this technology is relatively constant.[370] Several plants with less than 2000 MW wet-scrubbed capacity that have installed biological treatment systems, demonstrating that the costs were not unmanageable for these facilities. Allen, one of the plants setting the basis for BAT, has only 1155 MW of wet-scrubbed capacity. Mountaineer, another plant that has installed the technology that EPA has designated as BAT, is a single-boiler 1300 MW plant. Finally, the Mayo plant, which had installed biological treatment before recently deciding to switch to mechanical evaporation, is only 736 MW. Merrimack Station, where EPA Region 1 concluded that chemical precipitation followed by biological treatment was BAT—and therefore, implicitly affordable—has only 470 MWs of wet-scrubbed capacity. Clearly, EPA's threshold would exclude many plants at which it is economical to install this technology.

Moreover, the argument that larger units "are more able to achieve these limits based on economies of scale" confuses technological feasibility and economic cost. There is no evidence in the record that the chemical precipitation and biological treatment systems do not work as well

[369] 78 Fed. Reg. at 34,470.
[370] ERG Non-CBI Subcategorization Memo, EPA-HQ-OW-2009-0819-2258, at Figures 5-6.

for facilities with less than 2,000 MW of wet-scrubbed capacity.[371] This is simply an argument about cost disguised as one about technological feasibility.

Finally, EPA refers to its previous statements that relying on case-by-case determinations will further stimulate and support advanced pollution control technologies. The determination of Congress was just the opposite—that it is the setting of strong nationwide effluent limitation guidelines, based on the best-performing technology, that would drive technological advancement and achieve the national goal of eliminating water pollution.[372] As a practical matter, there is little if any incentive for industry to develop pollution controls when it is entirely unpredictable what level of pollution control, if any, a given state will require for a given facility on a case-by-case basis.

The rulemaking record is devoid of any basis for a 2,000 MW threshold. According to the documentation of changes made during Executive Order 12688 review, Option 3b and its 2,000 MW threshold were inserted by OMB,[373] which explains the lack of any evidence in the record for this threshold. The Agency's last-minute effort to create a record regarding Option 3b consists of one memorandum to the rulemaking record, entitled Methodologies for Estimating Costs and Pollutant Removals for Steam Electric ELG Regulatory Options 3a and 3b.[374] That memorandum calculates industry level compliance costs for Option 3b, but does not provide any information concerning how costs may be different for larger plants than smaller plants. Nor does this memorandum break out the capital and O&M costs for the FGD control technologies, making it impossible to evaluate whether EPA has any basis for the 2,000 MW threshold.

According to EPA, only 17 plants in the country have wet-scrubbed capacity of more than 2,000 MW.[375] However, EPA's list of these plants has been designated CBI,[376] even though the generating capacity and pollution control technology installed on boilers is matter of extensive public record. We compiled data from Form EIA-860 and EPA's National Electric Energy Data System (NEEDS) to create our own list of the small number of coal-burning power plants that would be subject to BAT under Option 3b, shown in the Table below. We count 20 such plants, although three of these operate zero liquid discharge systems or already have the biological treatment technology in question. The Gavin plant does not discharge FGD wastewater because it has a complete recycle system,[377] and Belews Creek and Roxboro are already operating the chemical precipitation plus biological treatment technology.

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[371] If there were a rational minimum threshold for effective operation of the biological treatment system, it would likely be based on FGD blowdown flow rates, which depend as much or more on coal type and FGD design, than on unit generating size.
[372] 33 U.S.C. § 1311(b)(2)(A); *see also NRDC v. EPA*, 822 F.2d 104, 123 (D.C. Cir. 1987) (stating that "the most salient characteristic of this [CWA] statutory scheme, articulated time and again by its architects and embedded in the statutory language, is that it is technology-forcing").
[373] *See* OMB Redline at 20.
[374] Docket No. EPA-HQ-OW-2009-0819-2145, at Table 2-1.
[375] Docket No. EPA-HQ-OW-2009-0819-2145, at 4.
[376] Docket No. EPA-HQ-OW-2009-0819, DCN: SE03881.A1 EPA-HQ-OW-2009-0819-2145.
[377] 2009 Final Detailed Study, EPA-HQ-OW-2009-0819-0387, at Table 2-1, p. 4-38.

These 20 plants represent only 17% of the plants with wet FGD systems—the rest would be excluded from the biological system BAT requirement, with BAT to be established on a case-by-case basis.[378]

Table 3 – Steam EGUs with More than 2,000 MW Wet-Scrubbed Capacity

Plant Name	State	# of Boilers	MW Wet-Scrubbed
Bowen	GA	4	3499
Gibson	IN	5	3340
James H Miller Jr.	AL	4	2824
Bruce Mansfield	PA	3	2742
General James M Gavin	OH	2	2600
Cumberland	TN	2	2600
Paradise	KY	3	2558
Roxboro	NC	4	2558
J M Stuart	OH	4	2440
Navajo	AZ	3	2409
Cross	SC	4	2390
Martin Lake	TX	3	2379
Jim Bridger	WY	4	2318
Colstrip	MT	4	2272
Four Corners	NM	5	2269
Ghent	KY	4	2226
Jeffrey Energy Center	KS	3	2160
Belews Creek	NC	2	2160
AES Petersburg	IN	4	2147
Harrison Power Station	WV	3	2052
		Total	49,943 MW
Source: EIA Form 860 (2012) (generating unit size); National Electric Energy Data System Annual Coal Unit Characteristics (2012) (sulfur dioxide control technology installed)			

The nearly 50,000 MW of generating capacity represented by these plants amounts to less than half of the wet-scrubbed capacity in the United States.[379] Thus, as a rough estimate, Option 3b would fail to address half of the FGD wastewater pollution in the country, or close to 12 billion gallons.[380]

Although EPA may establish subcategories based on cost in limited circumstances, the record does not, and could not, support a subcategory accounting for less than 20% of the industry, and addressing only half of the pollutant loading.

[378] This percentage is obtained by dividing 20 by 117, the number of plants EPA identified as having wet scrubber systems as of December 2014. TDD at 6-7.
[379] 2009 Final Detailed Study, EPA-HQ-OW-2009-0819-0387.at Table 4-2 (108,000 MW of wet-scrubbed capacity).
[380] 78 Fed. Reg. at 34,449 (estimating 23.7 billion gallons of FGD wastewater discharged in 2009).

IV. DRY ASH HANDLING IS BAT FOR FLY ASH TRANSPORT WATER.

BAT for fly ash is dry handling because eliminating the discharge of fly ash transport water is technologically and economically achievable. The Clean Water Act provides that, in setting BAT-based effluent limitations, EPA "shall require the elimination of discharges of all pollutants" in a wastewater stream if EPA finds that it is technologically and economically achievable to do so.[381] The record indicates that technologies for dry handling of fly ash are widely available and the costs can be reasonably borne by the electric power industry. Accordingly, eliminating the discharge of fly ash transport water is technologically and economically achievable and is BAT.

Fly ash transport water is one of the highest volumes of wastewater generated by power plants, and contains high concentrations of toxic pollutants. The average plant that generates fly ash transport water produces 2.4 million gallons of fly ash transport water per day.[382] The electric industry discharged 81.1 billion gallons of fly ash transport water to surface waters in 2009.[383] Given the volume of these toxic discharges, it is critical that EPA set BAT limits based on dry handling. Indeed, for over 30 years, Clean Water Act New Source Performance Standards have already required dry fly ash handling for new sources,[384] and companies have both built and retrofit hundreds of units that meet this standard. It is long since time that EPA require all existing facilities to do the same. All of the proposed options, except Options 1 and 2, would require dry handling.

A. ELIMINATING THE DISCHARGE OF FLY ASH TRANSPORT WATER IS TECHNOLOGICALLY ACHIEVABLE.

As EPA notes, several technologies are widely available for existing power plants to convert to dry handling of their fly ash. The most widely used systems are dry vacuum, pressure, and combination systems (that use both a vacuum and pressure system).[385] EPA based its cost estimates on dry vacuum systems for units other than oil units operating less than 100 days per year,[386] presumably because the majority of units that dry handle their ash use dry vacuum systems.[387]

The availability of technologies for the dry handling of fly ash is unsurprising given that EPA in 1982 established New Source Performance Standards requiring new units to eliminate the discharge of fly ash transport water.[388] In 1982, EPA noted that "[a]lmost half of the existing plants already use dry fly ash systems."[389] As a result of the 1982 effluent limitations guidelines, for over 30 years, new power plants have been installing these systems. Moreover, many

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381 33 U.S.C. § 1311(b)(2)(A).
382 78 Fed. Reg. at 34,449.
383 *Id.*
384 *See* 40 C.F.R. § 423.15(g).
385 TDD at 7-22 to 7-29.
386 Incremental Costs and Pollutant Removals at 7-1.
387 77 Fed. Reg. at 34,453.
388 47 Fed. Reg. 52,290, 52,296 (Nov. 19, 1982).
389 *Id.*

existing units have converted from wet to dry systems. Since 2000, 115 units have converted from wet fly ash handling to dry systems.[390]

Overall, the vast majority of existing units dry handle their fly ash. 66 percent of coal and coke units use a dry system only, and an additional 15 percent dry handle their fly ash but have a wet system as a backup.[391] Only 19 percent of coal and coke units rely exclusively on a wet system for handling fly ash.[392]

Several vendors offer systems for dry handling of fly ash.[393] The widespread use of dry systems at new and existing units, combined with the existence of multiple vendors selling the technologies, confirms that technologies for dry handling of fly ash are available.

B. THE ELECTRIC POWER INDUSTRY CAN AFFORD THE TECHNOLOGIES THAT WOULD ELIMINATE THE DISCHARGE OF FLY ASH TRANSPORT WATER.

As explained above in Section II, the relevant test for economic achievability is whether the costs can be reasonably borne by the industry as a whole.[394] The technologies for dry fly ash handling meet this test.

The economic impact of requiring dry handling of fly ash is relatively small given that the overwhelming majority of plants that generate fly ash already use dry handling technology. EPA projects that basing the BAT limits on dry handling would cause 66 plants[395] to incur compliance costs.[396] This amounts to only 12-13 percent of all coal, coke, and oil plants.[397] Put differently, 87-88 percent of all coal and oil plants would have zero compliance costs to comply with a BAT standard based on dry handling of fly ash.

Even if EPA focuses on the 481 coal, coke, and oil plants that generate fly ash,[398] only 14 percent of plants would face compliance costs. And even if the agency zeroes in on coal and coke plants, which generate the greatest amount of fly ash, only 19% of coal and coke plants would face compliance costs.[399] 81% of coal and coke plants would face zero compliance costs because they already have dry handling systems in place. A rule that would lead 81% of the most affected plants to incur no compliance costs is economically achievable.

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[390] TDD at 4-22 to 4-23.
[391] *Id.* at 7-23.
[392] *Id.*
[393] Incremental Costs and Pollutant Removals at 7-2 (noting that Clyde Bergemann Power Corporation and United Conveyance Corporation market dry vacuum systems).
[394] *Waterkeeper Alliance v. EPA*, 399 F.3d 486, 516 (2d Cir. 2005); *Rybachek v. EPA*, 904 F.2d 1276, 1290-91 (9th Cir. 1990); *Am. Iron & Steel Inst. v. EPA*, 526 F.2d 1027 (3d. Cir. 1975).
[395] This excludes certain small (<50MW) and oil-fired units. If those plants are included, 76 plants would incur costs to convert from wet-sluicing to dry vacuum handling of fly ash. Incremental Costs and Pollutant Removals at 7-4.
[396] *Id.* at 7-4 n.43.
[397] *See* TDD at 4-16 (calculating that there are 527 to 552 coal, coal, and oil plants).
[398] *Id.* at 7-22.
[399] *Id.* at 7-23.

The total, industry-wide cost of a zero discharge standard can be reasonably borne by the industry. EPA calculates that the 66 plants that would have to convert to dry handling would spend $398 million on capital costs, $177 million on operating and maintenance costs per year, and an additional $20.7 million per year on 10-year recurring costs.[400] We are unable to comment on the compliance costs for specific plants, since the plant-level data has been redacted by EPA.[401] As a rough guide to the plant-level costs, we divided these costs by 66, the number of affected plants. Based on this calculation, the average plant would incur $6 million in capital costs and approximately $3 million in O&M costs per year.[402]

Whatever cost metric one uses, these costs are achievable for the electric sector as a whole. Since EPA has analyzed the cost of regulatory options rather than the component costs of treating different waste streams, we can examine the economic impact of the various options that include dry handling of fly ash as BAT. EPA conducted the full suite of cost analyses for only two options, Options 3 and 4. Option 4 includes dry handling for fly ash, and the record demonstrates that Option 4 is economically achievable, which means that each of the component parts of Option 4—including dry fly ash handling—is economically achievable.[403]

For Options 3 and 4, EPA presented a cost-to-revenue screening analysis. Option 4 would cause 798 plants to devote 0% of their revenues to compliance costs; 117 plants would spend 1-3% of the revenues on costs, and only 48 plants would have a cost-to-revenue ratio greater than 3%.[404] EPA asserts that "entities incurring cost below 1% of revenue are unlikely to face economic impacts,"[405] and 84% of plants will have costs at or below 1% of revenues. This suggests that the industry as a whole can easily bear the cost of dry fly ash handling that is part of the cost of Option 4.

Option 4 would increase variable production cost by only 1% on a per megawatt hour basis.[406] EPA modeling indicates that Option 4 would result in only a .1% increase in retirements (relative to the baseline capacity of the industry).[407] Even if all of the costs of Option 4 were attributable to dry fly ash handling – which they obviously are not – the costs are so small that only .1% of total industry capacity would retire early.

Finally, the cost effectiveness of requiring dry handling of fly ash is $27 per TWPE,[408] which is well within the range of cost effectiveness values EPA has found reasonable in other ELGs.[409]

[400] *Id.* at 9-40.
[401] *See* Appendices to Incremental Costs and Pollutant Removals.
[402] TDD at 9-40.
[403] Like Option 4, Option 3 is economically achievable. However, in the technologies proposed as BAT for waste streams other than fly ash transport water fall, Option 3 falls far short of what the Clean Water Act requires.
[404] 78 Fed. Reg. at 34,494.
[405] 78 Fed. Reg. at 34,495.
[406] 78 Fed. Reg. at 34,498.
[407] *Id.*
[408] TDD at 8-34.
[409] RIA at D-8 (11 final effluent limitations guidelines have cost-effectiveness values greater than or equal to $27 for direct dischargers).

In short, whether one determines economic achievability based on the total cost to industry, cost to revenue ratios, plant closures, or cost-effectiveness, dry handling of fly ash is economically achievable. As explained *infra* Section IX, it is unlawful for EPA to base its BAT determination on cost metrics other than the standard for economic achievability articulated by the courts, namely, whether the costs can be reasonably borne by the industry as a whole. But even assuming, for the sake of argument, that all of the cost metrics EPA has evaluated in this rulemaking are appropriate potential bases for a BAT determination, dry fly ash handling is economically achievable under any of them. Therefore, there can be no dispute that the cost of dry fly ash handling can be reasonably borne by the industry as a whole and therefore is economically achievable.

C. NONE OF THE OTHER BAT FACTORS WEIGHS AGAINST DETERMINING THAT DRY HANDLING IS BAT FOR FLY ASH TRANSPORT WATER.

The Clean Water Act requires consideration of factors other than technological availability and economic achievability, namely "the age of equipment and facilities involved, the process employed, the engineering aspects of the application of various types of control techniques, process changes, the cost of achieving such effluent reduction, non-water quality environmental impact (including energy requirements)," and other factors EPA deems appropriate.[410] None of these factors alters the conclusion that the statute requires EPA to set effluent limits that eliminate the discharge of fly ash transport water because the technology is available and doing so is economically achievable.[411]

EPA has considered the age of equipment and the age of the plants that would need to convert to dry fly ash handling; specifically, EPA considered the age of equipment and plants in determining the costs of retrofitting existing units.[412] Similarly, EPA considered the engineering aspects of dry vacuum, pressure, and combination systems, and found that they are widely used; EPA used dry vacuum systems as the basis of its cost estimates based in part on EPA's findings that dry vacuum systems can be engineered for a wider variety of plants than pressure systems.[413] As explained above, the cost of dry fly ash handling can be reasonably borne by the industry. Turning to the final factor, dry fly ash handling has environmental benefits other than water quality. For example, it reduces water consumption. Even in areas of the country where water is not scarce, reducing water withdrawals reduces entrainment and impingement of aquatic organisms and ensures that more water remains in the ground and in surface flows for humans and wildlife.[414]

Technologies are commercially available and have been widely used to dry handle fly ash. The cost of converting approximately 66 plants from wet systems to dry systems can be reasonably borne by the industry as a whole. None of the additional statutory factors weighs against determining that BAT for fly ash is dry handling. As a result, sections 1314(b)(2)(B) and

[410] 33 U.S.C. § 1314(b)(2)(B).
[411] *See id.* § 1311(b)(2)(B).
[412] *E.g.*, Incremental Costs and Pollutant Removals at 7-1, 7-4; ERG Subcategorization Memo at 2-3.
[413] TDD at 7-28.
[414] EA at 6-48; Benefit and Cost Analysis at 2-11, 2-13, 9-1 to 9-2.

1311(b)(2)(B) of the Clean Water Act instruct EPA to set effluent limits for all steam electric plants that eliminate the discharge of fly ash transport water.

V. BAT FOR BOTTOM ASH TRANSPORT WATER IS ZERO DISCHARGE.

EPA should set BAT limits based on zero discharge of bottom ash transport water for all units. EPA estimates that in 2009, power plants generated 255 billion gallons of bottom ash transport water, which amounts to 2.5 million gallons per day per plant, on average.[415] These transport waters poison our waterways with a host of toxic pollutants, including arsenic, cadmium, lead, mercury, and selenium.[416]

However, affordable technologies can completely eliminate these discharges. EPA reviewed six separate methods for eliminating bottom ash transport water discharges; these systems can be divided between systems such as mechanical and remote mechanical drag systems that use water but recycle it, and systems such as vacuum and pressure systems that use no water at all.[417] EPA's analysis of the cost of meeting a zero discharge standard for bottom ash is based on mechanical and remote mechanical drag systems.[418] Options 4 and 5 would set BAT limits based on elimination of bottom ash transport water discharges; Option 4a would require only units greater than 400 MW to eliminate those discharges.[419]

The record demonstrates that all plants can install and afford zero discharge systems such as mechanical drag systems, remote mechanical drag systems, or vacuum and pressure systems. As explained below, the cost of converting to zero discharge systems can be reasonably borne by the industry, even using EPA's cost estimates. However, EPA significantly overestimated costs by ignoring economies of scale, counting units that will likely retire or convert regardless of this rule, overestimating operating and maintenance costs, and using an inappropriately high annualization factor. If the more accurate, lower cost estimates are used, the evidence that zero discharge systems are economically achievable is even more overwhelming.

The 1972 Clean Water Act amendments promised to eliminate water pollution, and it is time for EPA to make good on that promise. The Act instructs EPA to establish effluent limitations that "shall require the elimination of discharges of all pollutants if the Administrator finds . . . that such elimination is technologically and economically achievable."[420] The record demonstrates that eliminating the discharge of bottom ash transport water is both technologically and economically achievable for all units and therefore the final guidelines must be based on a zero discharge standard for bottom ash transport water.

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415 TDD at 6-9.
416 TDD at 10-18 to 10-19.
417 78 Fed. Reg. at 34,453-54.
418 Incremental Costs and Pollutant Removals at 8-1.
419 *Id.* at 34,458.
420 33 U.S.C. § 1311(b)(2)(A).

A. ELIMINATING THE DISCHARGE OF BOTTOM ASH TRANSPORT WATER IS TECHNOLOGICALLY ACHIEVABLE.

Based on the number of plants operating zero discharge systems and the number of vendors that commercially market such systems, it is undisputed that mechanical and remote mechanical drag systems are available. For the purposes of BAT limits, a technology is available even if it is used at only the single, best-performing plant.[421] A technology is available if it has been studied and demonstrated to work, such as through the use of pilot studies; the technology need not be in commercial use to be considered available.[422] This contrasts with the less-stringent BPT guidelines, which are based on the average of the best-performing plants.[423] Ninety-five coal and coke units operate mechanical drag systems.[424] More than 80 percent of coal-burning units built in the last 20 years have installed zero discharge bottom ash handling systems.[425] In addition to the existing plants operating zero discharge systems, 74 units at 19 plants plan on converting from wet to dry handling of bottom ash.[426]

Clyde Bergemann and United Conveyor Corp. market mechanical drag and remote mechanical drag systems; Allen-Sherman-Hoff markets a recirculation system.[427] United Conveyor Corporation, a vendor of dry bottom ash handling systems, advised EPA that 98 percent of plants could convert from wet to dry systems such as mechanical or remote mechanical drag systems.[428] The large number of plants operating mechanical drag and remote mechanical drag systems, and the number of vendors offering such systems, confirms EPA's conclusion that "all plants, regardless of size, are capable of installing and operating dry handling or closed-loop systems for bottom ash transport water."[429]

Zero discharge systems that use no water at all, such as vacuum and pressure systems, are also technologically achievable, as demonstrated by the plants operating the systems and the vendors offering them commercially. In the United States, 66 plants have installed dry vacuum systems and 11 plants have installed dry pressure systems.[430] Magaldi offers the Magaldi Ash Cooler (MAC) system, and Clyde Bergemann offers the DRYCON system.[431] Both systems use air, rather than water, to cool the hot bottom ash, and transport the ash without using water. *Id.*

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[421] *Chem. Mfrs. Ass'n v. EPA*, 870 F.2d 177, 226 (5th Cir. 1989) ("Congress intended these [BAT] limitations to be based on the performance of the single best-performing plant in an industrial field."); see also *NRDC v. EPA,* 863 F.2d 1420, 1426 (9th Cir. 1988).

[422] See *Kennecott*, 780 F.2d at 448 ("In setting BAT, EPA uses not the average plant, but the optimally operating plant, the pilot plant which acts as a beacon to show what is possible."); *Am. Petroleum Inst.*, 858 F.2d at 265 (for BAT, "a process is deemed 'available' even if it is not in use at all"); *FMC Corp.*, 539 F.2d at 983-84 (upholding BAT for chemical oxygen demand based on performance data from a single pilot plant).

[423] *Chem. Mfrs. Ass'n*, 870 F.2d at 207-08.

[424] TDD at 7-31.

[425] 78 Fed. Reg. at 34,470.

[426] TDD at 7-30 to 7-31.

[427] Fox Report, Appendix E, at 5-8.

[428] EPA, Notes from USEPA-UCC Conference Call with United Conveyor Corporation at 3 (Jan. 6, 2010), Docket No. EPA-HQ-OW-2009-0819-0422.

[429] 78 Fed. Reg. at 34,470.

[430] 78 Fed. Reg. at 34,454.

[431] Fox Report, Appendix E, at 9.

B. ELIMINATING THE DISCHARGE OF BOTTOM ASH TRANSPORT WATER IS ECONOMICALLY ACHIEVABLE.

A technology is economically achievable if the costs of the technology can be reasonably borne by the industry as a whole.[432] The record indicates that the steam electric industry can reasonably bear the costs of converting all units to zero discharge systems. EPA estimated the cost of converting to a zero discharge system based on mechanical drag and remote mechanical drag systems. While these two systems are economically achievable, dry vacuum and pressure systems are also economically achievable, and may have even lower costs. The record reflects that the industry as a whole can reasonably bear the cost of installing and operating the many systems capable of meeting a zero discharge standard for bottom ash transport water.

1. Even using EPA's cost figures, the cost of a zero discharge standard can be borne by the industry.

EPA calculated the cost of meeting a zero discharge standard for bottom ash based on the installation and operation of mechanical drag and remote mechanical drag systems. EPA estimates that requiring all units greater than 50 MW to meet a zero discharge standard would require retrofits at 240 plants with a capital cost of $4.5 billion and annual O&M costs of $494 million.[433] On average, each plant would incur $17 million in capital costs and $2 million in annual O&M costs. Since 240 plants will incur compliance costs,[434] and there are a total of 1079 plants,[435] only 22% of all plants would incur compliance costs. Put differently, 78% of plants in the industry would have zero compliance costs as a result of a zero discharge standard for bottom ash transport water.[436] The costs can be reasonably borne by the industry, when judged by any of the cost metrics EPA employs: total costs; impact on retirements and generation; cost-to-revenue ratio; and cost-effectiveness.

EPA's analyses of Option 4, which would require zero discharge of bottom ash transport water for all units greater than 50 MW, show that the economic impact of requiring zero discharge of bottom ash can be reasonably borne by the industry as a whole. Option 4 would increase annual costs by approximately 1.4% and increase variable production costs by 1%.[437] Option 4 would cause a 0.1% increase in unit retirements.[438] Even if all of the costs of Option 4 were attributed to zero discharge of bottom ash transport water – which they are not, making it a highly conservative assumption – the costs could still be reasonably borne by industry, since they would increase annual costs by roughly 1% and cause a less than 1% increase in unit retirements.

[432] *Waterkeeper Alliance v. EPA,* 399 F.3d 486, 516 (2d Cir. 2005); *Chem. Mfrs. Ass'n v. EPA*, 870 F.2d 177, 262 (5th Cir. 1989).
[433] TDD at 9-40.
[434] *Id.*
[435] 78 Fed. Reg. at 34,447.
[436] At the unit level, EPA estimates that these 240 plants consist of 634 units that would incur compliance costs, Incremental Costs and Pollutant Removals at 8-2, out of 2195-2230 units in the industry, 78 Fed. Reg. at 34,448. As a result, 28% of all units would face compliance costs. 72% of units in the industry would have no costs to comply with a zero discharge standard for bottom ash transport water.
[437] 78 Fed. Reg. at 34,498.
[438] *Id.*

The impacts of Option 4 are also reasonable when viewed through the lens of cost-to-revenue ratios. Under a zero discharge standard for plants greater than 50 MW, 85 percent of plants would incur costs that are less than 1 percent of revenues,[439] which EPA claims means that they "are unlikely to face economic impacts."[440] Under Option 4, only 48 plants – 4 percent of the industry – would incur compliance costs greater than 3 percent of revenues. And those costs include the cost to treat all waste streams (FGD wastewater, fly ash transport water, etc.). Given that the costs of Option 4 as a whole are achievable, the component cost to convert all units greater than 50 MW to zero discharge systems is also achievable.

Zero discharge of bottom ash is economically achievable if cost-effectiveness is considered as well. Requiring all units greater than 50 MW to meet a zero discharge standard for bottom ash transport water would cost $107 per TWPE.[441] This is well within the cost-effectiveness values that EPA has approved in other effluent limitations guidelines; $107 per TWPE is lower than the cost-effectiveness of the final ELGs for seven separate industries.[442] EPA has issued final effluent limitations guidelines with cost-effectiveness values nearly four times as high as the cost-effectiveness of bottom ash retrofits.[443]

As we explain elsewhere in these comments, the Clean Water Act does not authorize EPA to use cost-effectiveness as the sole or primary basis of a BAT determination; the correct legal standard is whether costs can be borne by the industry as a whole.[444] However, if EPA considers cost-effectiveness, the Agency should find that a zero discharge standard for bottom ash transport water is cost-effective, given that EPA has approved of cost-effectiveness values higher than $107 in several other ELGs. This review of the various cost metrics demonstrates that under any of the cost analyses conducted by EPA in this rulemaking, a zero discharge standard for bottom ash transport water is economically achievable for all plants.

2. *The actual costs of a zero discharge standard are far lower than EPA calculated.*

A zero discharge standard for bottom ash transport water for all units greater than 50 MW is economically achievable – even if one uses EPA's cost numbers. But EPA has inflated the cost of bottom ash retrofits. As explained in detail in the accompanying expert report by Dr. Phyllis Fox,[445] EPA overestimated the cost of converting to zero discharge of bottom ash transport water in several ways. Specifically, EPA: (1) did not account for economies of scale in designing and installing retrofits; (2) included units that are likely to convert to dry bottom ash handling for reasons other than compliance with this rule; (3) overestimated operating and maintenance costs; and (4) used a shorter equipment lifetime and higher interest rate, leading to a higher

[439] 78 Fed. Reg. at 34,494.
[440] *Id.* at 34,495.
[441] TDD at 8-34.
[442] RIA at D-8 ($404 per TWPE for direct dischargers in the electrical and electronic components industry; $155, $175, $111, $116, $127, and $380 per TWPE for indirect dischargers in the aluminum forming, centralized waste treatment, leather tanning, metal molding and castings, metal products and machinery, and transportation equipment cleaning industries, respectively).
[443] *See id.*
[444] *See infra* Section IX.
[445] *See* Appendix E.

annualization factor. If some or all of these items were addressed, the total cost to industry and the per-unit costs of a zero discharge standard would decrease dramatically.

First, EPA appears to have calculated costs at the unit level, and then summed those costs to arrive at the total cost for the industry.[446] This methodology overestimates compliance costs because there are economies of scale when retrofitting multiple units at the same plant or multiple units at different plants owned by the same company.[447] There are several reasons why retrofitting multiple units at the same plant would cost less than retrofitting each unit individually. A bottom ash handling system can be designed to take advantage of bottom ash being an intermittent waste stream; a transport system can service multiple units that have offset the timing of the ash dump at each boiler.[448] Silos used to temporarily house the ash can serve multiple units. In addition, there are capital and labor savings, including multiple-unit discounts, when retrofitting multiple units together, rather than individually.[449]

EPA acknowledges that summing the per-unit costs overestimates compliance costs,[450] and information in the record corroborates EPA's statement. Site visits show that two 750 MW units at a single plant converted to dry bottom ash handling for $25 million in capital costs, whereas EPA's cost methodology would suggest the costs should have been $35 million, or nearly 40% more than the actual costs.[451]

Moreover, vendors stated that there are economies of scale to retrofitting multiple units at a single plant.[452] United Conveyor Corp. stated that "there [are] savings associated with remote MDS conversions at plants where there are multiple units."[453] UCC estimated that a remote mechanical drag system servicing three or four units at a plant would have costs 30 to 50 percent lower than the per-unit cost to retrofit each unit individually.[454] In short, there is ample evidence in the record that EPA's methodology overestimated costs by ignoring economies of scale.

Second, the total industry cost includes costs at several units that are likely to shut down or convert to zero discharge systems even in the absence of this rule. Companies have announced

[446] Incremental Costs and Pollutant Removals at 8-4; Fox Report, Appendix E, at 29-30.
[447] *Id.* at 29-32.
[448] *Id.* at 30.
[449] *Id.* at 30.
[450] Incremental Costs and Pollutant Removals at 8-20 to 8-21 "(Note that this may overestimate compliance costs for the proposed rule because multiple units at a plant could use the same remote MDS which would result in lower overall costs.)."
[451] Fox Report, Appendix E, at 31.
[452] Fox Report, Appendix E, at 32-33.
[453] EPA, Non-CBI Ash Handling Conversion Data and Bottom Ash Conversion Costs at 1, Attachment DCN SE01825A80 to Docket No. EPA-HQ-OW-2009-0819-2888. Additionally, UCC stated that "any successful cost model would need to take into account the appropriate economies of scale. For example, power plants converting multiple generating units to dry fly ash handling systems would not necessarily need more silos than that for one generating unit. UCC noted that a plant will likely have two ash storage silos if it is operating four generating units. UCC stated that similarly, power plants installing dewatering bins for multiple generating units could install one large dewatering bin rather than multiple ones. As an example, UCC mentioned that the Kingston plant installed a dewatering bin system for its nine generating units because it was more cost-effective than installing individual dry bottom ash handling systems on each of the nine generating units." EPA, Notes from USEPA-UCC Conference Call with United Conveyor Corporation at 6 (Jan. 6, 2010), Docket No. EPA-HQ-OW-2009-0819-0422.
[454] *Id.* at 27.

the retirement of 88 units that are included in EPA's calculation of the units that will incur compliance costs.[455] Moreover, over several years, zero discharge systems save money compared to systems that rely on wet sluicing of bottom ash. Vendors report a trend toward converting wet sluicing systems to zero discharge systems, and this trend is likely to continue because of economic and environmental considerations independent of this rule.[456] Removing units that already intend to retire or convert to zero discharge systems from the list of units that would incur compliance costs would significantly lower the total industry cost of a zero discharge standard.

Third, EPA's estimates of the per-unit operating and maintenance costs are higher than the actual costs incurred by plants. In fact, EPA's calculations have it backwards; zero discharge systems ultimately reduce O&M costs, rather than increase them.[457] Zero discharge systems reduce operating and maintenance costs because of several factors, including: lower auxiliary power usage; improve reliability which reduces the frequency of outages; reduced ash disposal costs; and no or lower water usage, which reduces associated costs.[458] For example, when Seminole Electric Cooperative converted two units to zero discharge systems, the company reported saving approximately $3 million per year in operating and maintenance costs.[459]

Finally, EPA's annualization method overestimates annual costs by a factor of nearly two. EPA used a 7% discount rate and 20-year equipment lifetime to annualize costs.[460] EPA selected a 7% discount rate based on the claim that it "is the real (i.e., inflation rate factored out) cost of capital as estimated by the U.S. Office of Management and Budget [OMB, 2003]" and has been used by EPA in the rulemakings.[461] But the referenced OMB document recommends that agencies use additional discount rates, including 3%, as sensitivity analyses to the use of a 7% discount rate.[462] Moreover, the OMB circular cautions that the appropriate discount rate changes over time as interest rates and rates of return change. Accordingly, with interest rates having plummeted since the circular was drafted in 2003, EPA's choice of only a 7% discount rate conflicts with the circular's recommendations.

The other primary component of the annualization method is the equipment lifetime. "EPA selected a timeframe of 20 years based on the expected operational life of the dry/closed-loop recycle bottom ash handling technology."[463] However, zero discharge systems have been used for longer than 20 years; a more appropriate equipment lifetime would be 30 years.[464] If EPA

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[455] *See* List of Announced Retirements Included in EPA's Cost Calculations, submitted by Commenters as an exhibit to this letter.
[456] Fox Report, Appendix E, at 36.
[457] Fox Report, Appendix E at 33-35.
[458] *Id.*
[459] Fox Report, Appendix E, at 39.
[460] 78 Fed. Reg. at 34,492; Incremental Costs and Pollutant Removals at 8-32.
[461] Incremental Costs and Pollutant Removals at 8-32.
[462] OMB, Circular A-4 (Sept. 17, 2003), *available at* http://www.whitehouse.gov/omb/circulars_a004_a-4/#d. This error in calculating the annualization factor affects all of EPA's cost calculations, not just the calculations for bottom ash conversions.
[463] Incremental Costs and Pollutant Removals at 8-32.
[464] Fox Report, Appendix E, at 45. Additionally, the useful life of dry handling systems is often assumed to be longer than 20 years; for example, a 1981 TVA study seems to have assumed that dry handling systems could

were to use a 3% interest rate – which is much closer to the interest rate on a 30-year treasury note – and equipment lifetime of 30 years, the annualization factor would be roughly half of what EPA used.[465] Bringing these inputs more in line with contemporary data would cut the costs of a zero discharge standard in half.

3. *Zero discharge systems that use no water are cheaper than the mechanical drag and remote mechanical drag systems EPA used for calculating costs.*

While EPA acknowledges that many systems for handling bottom ash eliminate the discharge of transport water, EPA based its cost estimates on only the mechanical drag and remote mechanical drag systems.[466] Both of these systems use water, but recycle rather than discharge the water. Other zero discharge systems use no water at all. These other systems are more cost-effective over the long run, as explained in detail in the accompanying expert report by Dr. Phyllis Fox.[467] As a result, the true cost of converting to a zero discharge system is lower than EPA estimated in the proposed rule. EPA should revise its cost estimates to reflect the lower costs of bottom ash handling systems that do not use water, such as dry vacuum and dry pressure systems.

Dry vacuum and dry pressure systems are economically achievable. While dry vacuum and pressure systems may have higher upfront capital costs than remote mechanical drag systems,[468] they have lower operating and maintenance costs. On a lifecycle basis, dry vacuum and dry pressure systems cost less than the mechanical and remote mechanical drag systems EPA costed.[469]

The cost savings come in part from recovering some of the heat energy from the ash. In mechanical and remote mechanical drag systems, the hot bottom ash is cooled by water, such that the heat energy in the bottom ash is wasted – it is used to evaporate the water, which then exits the system. The unburned carbon in the ash is not used to generate energy, but instead becomes solid waste.[470] However, in a dry vacuum or dry pressure system, the air used to cool the ash burns additional carbon, releasing additional thermal energy, which is returned to the boiler.[471] That, in turn, reduces the amount of fuel needed and the associated fuel costs. Vendors informed EPA that this improved efficiency results in lower costs for dry vacuum and dry pressure systems compared to mechanical drag systems. For example, United Conveyor Corp. stated that “this added efficiency makes completely dry technologies generally more cost-

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operate for the 35-year expected life of the new plant. *See* Economic Analysis of Wet Versus Dry Ash Disposal Systems (1981).

[465] Fox Report, Appendix E, at 45-46.

[466] Incremental Costs and Pollutant Removals at 8-1.

[467] Fox Report, Appendix E, at 21-28.

[468] However, dry vacuum and pressure systems may have lower capital costs than mechanical drag systems. EPA calculated that Clyde Bergemann’s DRYCON system, which uses no water, has lower installed capital costs than its SSC (mechanical drag) system. Indeed, the DRYCON system is between $1 million and $2 million cheaper to install than the SSC mechanical drag system, depending on the size of the unit. EPA, Non CBI Bottom Ash MDS Capital Costs, at Tab “MDS Capital Cost,” DCN SE01825A74, attachment to EPA-HQ-OW-2009-0819-2888.

[469] Fox Report, Appendix E, at 22, 24.

[470] Fox Report, Appendix E, at 26.

[471] Fox Report, Appendix E, at 9, 26.

effective than SFC systems [mechanical drag systems that use water] in the long-term, although the payback period may be several years."[472]

Clyde Bergemann recently wrote to EPA expressing its surprise that EPA had neglected zero discharge systems that do not use water. Clyde Bergemann explained the cost savings from a recent installation of its DRYCON system, which uses air pressure, rather than water, to convey bottom ash away from the boiler.

> [T]wo boiler Units in Florida with DRYCON™ conveyors under them came back on line in April and November of 2012 after less than 22 day outages to remove the entire wet ash systems. The two 650+ MW Units are now operating at full load with the added benefits in 2013 that:
>
> - The use of water to operate the entire bottom ash and economizer ash handling systems has been totally eliminated.
> - The power consumption to operate the bottom ash and economizer ash handling systems has been greatly reduced.
> - The amount of unburned carbon in the ash, also referred to as loss-on-ignition, LOI, has been significantly reduced as verified by field measurements.
> - The bottom ash temperature is significantly reduced between the boiler throat opening and the end of the conveyor.
> - The plant has experienced significantly reduced operating and maintenance costs.
>
> We believe this installation validates the many reasons why our DRYCON™ Dry Bottom Ash Conveyor should be added to the list of available and viable technologies for new and existing bottom ash handling systems.[473]

Dry vacuum and pressure systems have additional cost savings. Since these systems use no water at all, the resulting ash is dry, which is more easily marketed.[474] If the ash is not sold, the landfill costs for dry ash are lower than the cost for wet ash.[475] Finally, dry vacuum and pressure systems have fewer operating and maintenance problems because they do not use the metal chain systems used in mechanical and remote mechanical drag systems.[476]

C. THE OTHER BAT FACTORS DO NOT ALTER THE CONCLUSION THAT BAT LIMITS SHOULD BE BASED ON THE USE OF ZERO DISCHARGE SYSTEMS.

The Clean Water Act requires consideration of factors other than technological availability and economic achievability, namely "the age of equipment and facilities involved, the process employed, the engineering aspects of the application of various types of control techniques,

[472] EPA, Notes from USEPA-UCC Conference Call with United Conveyor Corporation at 6-7 (Jan. 6, 2010), Docket No. EPA-HQ-OW-2009-0819-0422.
[473] Letter from Gary Mooney, Clyde Bergemann, to EPA at 2 (June 26, 2013), Docket No. EPA-HQ-OW-2009-0819-2927.
[474] Fox Report, Appendix E, at 27.
[475] *Id.*
[476] *Id.* at 27-28.

process changes, the cost of achieving such effluent reduction, non-water quality environmental impact (including energy requirements)," and other factors EPA deems appropriate.[477] None of these factors alters the conclusion that the statute requires EPA to set effluent limits eliminating the discharge of bottom ash transport water because zero discharge systems are technologically and economically achievable.[478]

EPA has considered the age of equipment and the age of the plants that would need to convert to zero discharge systems; specifically, EPA considered the age of equipment and plants in determining the costs of retrofitting existing units.[479] Similarly, EPA considered the engineering aspects of mechanical drag, remote mechanical drag, vacuum, pressure, recycle, vibratory belt, and mechanical systems.[480] As explained above, the cost of meeting a zero discharge standard for bottom ash transport water can be reasonably borne by the industry. Turning to the final factor, zero discharge of bottom ash transport water has environmental benefits other than improved water quality. For example, it reduces water consumption. Even in areas of the country where water is not scarce, reducing water withdrawals reduces entrainment and impingement of aquatic organisms and ensures that more water remains in the ground and in surface flows for humans and wildlife.[481]

D. SETTING LESS STRINGENT BAT LIMITS FOR UNITS LESS THAN 400 MW IS UNSUPPORTED BY THE RECORD.

One of EPA's proposed options, Option 4a, would set BAT limits equal to the current BPT limits for units with a capacity equal to or less than 400 MW. Option 4a would authorize 125 plants to continue to discharge bottom ash transport water after sending such water to impoundments, where the water receives minimal treatment in order to comply with limits for only TSS and oil and grease. Compared to Option 4, adopting Option 4a would allow the discharge of an additional 714,000,000 pounds of pollutants of concern and 1.1 million pounds per year of toxic weighted pollutants.[482]

Option 4a was not one of the options originally developed by EPA. Instead, it is the product of political interference by OMB during the regulatory review process. So it should come as no surprise that an option inserted at the last minute, after a highly politicized regulatory review process, conflicts with data in the record. Setting BAT limits for bottom ash transport water based on a 400 MW threshold is unsupported by the record and inconsistent with the Clean Water Act.

1. The 400 MW threshold is arbitrary and unsupported by the record.

EPA advances two primary rationales for the 400 MW threshold, but neither rationale is supported by the record. EPA claims that units 400 MW or smaller face disproportionately

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[477] 33 U.S.C. § 1314(b)(2)(B).
[478] *See id.* § 1311(b)(2)(B).
[479] *E.g.,* Incremental Costs and Pollutant Removals at 8-1, 8-9; ERG Subcategorization Memo at 4-5.
[480] 78 Fed. Reg. at 34,453-54.
[481] EA at 6-48; Benefit and Cost Analysis at 2-11, 2-13, 9-1 to 9-2.
[482] Fox Report, Appendix E, at 15.

higher compliance costs relative to larger units.[483] EPA also contends that "while all plants, regardless of size, are capable of installing and operating dry handling or closed-loop systems," the Agency "believes that companies may choose to shut down 400 MW and smaller units" in order to comply with a zero discharge standard.[484]

To begin, the record demonstrates that many units at plants with a capacity equal to or less than 400 MW have installed zero discharge systems. Using the sanitized version of the responses to the industry questionnaire, we determined that 153 coal units are located at plants with a capacity equal to or less than 400 MW and which do not use wet sluicing.[485] This suggests that many smaller plants have been able to afford to convert to bottom ash handling systems other than wet sluicing, such as dry vacuum systems and mechanical drag systems.

EPA's claim that units less than or equal to 400 MW are likely to incur disproportionately higher compliance costs than larger units is not supported by any analysis in the record.[486] The only publicly available information[487] in the docket flatly contradicts EPA's assertion that 400 MW represents a meaningful threshold concerning the cost of converting units to dry bottom ash handling. ERG, EPA's contractor, drafted a memorandum evaluating various subcategorization approaches. Figures 3 and 4 plot the annualized cost of zero discharge systems for bottom ash handling as a function of unit capacity.[488] The figures indicate that 400 MW does not represent a meaningful threshold in the cost of bottom ash retrofits. From approximately 100 MW onward, the retrofit cost is represented by a smooth line with a small slope. To the extent that there is a threshold below which costs increase dramatically, at a much greater slope than at other points on the line, the threshold is 50 MW.[489] Moreover, the incremental cost-effectiveness of subjecting units with a capacity equal to or less than 400 MW to a zero discharge standard is minimal: cost-effectiveness changes from $99 per TWPE for units greater than 400 MW to $107 per TWPE for units greater than 50 MW.[490]

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[483] 78 Fed. Reg. at 34,470.
[484] *Id.*
[485] *See* Bottom Ash Zero Discharge Systems at Plants Equal to or Less Than 400 MW. Dry vacuum systems are the most common systems in use at these plants for handling bottom ash, followed by mechanical drag systems.
[486] *See* 78 Fed. Reg. at 34,470 (the cost "per MW for a 200 MW unit is more than three times higher than the average cost for a 400 MW unit").
[487] We are unable to meaningfully comment on this unsubstantiated assertion based on EPA failing to offer any publicly available information in support of this contention. If EPA were to adopt Option 4a, and rely on non-public information as the basis for the BAT limits for bottom ash transport water, EPA would be violating basic notice and comment requirements in the APA and the Clean Water Act. *See, e.g., Chem. Mfrs. Ass'n v. EPA*, 870 F. 2d 177, 200 (5th Cir. 1989) ("fairness requires that the agency afford interested parties an opportunity to challenge the underlying factual data relied on by the agency"); *United States v. Nova Scotia Food Prods. Corp.*, 568 F.2d 240, 252 (2d Cir. 1977) ("[t]o suppress meaningful comment by failure to disclose the basic data relied upon is akin to rejecting comment altogether"); *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375, 393 (D.C. Cir. 1973) ("[i]t is not consonant with the purpose of a rule-making proceeding to promulgate rules on the basis of inadequate data, or on data that, [to a] critical degree, is known only to the agency").
[488] ERG Subcategorization Memo at 10-11.
[489] Similarly, cost curves for the capital cost of mechanical drag systems contradict EPA's assertion that a 200 MW unit is three times more expensive to retrofit than a 400 MW unit. To install Clyde Bergemann's mechanical drag system, units with a capacity between 150 to 300 MW would incur $9 million in capital costs, whereas 300 to 500 MW units would incur $13 million in capital costs. EPA, Non CBI Bottom Ash MDS Capital Costs, DCN SE01825A74, attachment to EPA-HQ-OW-2009-2888.
[490] 78 Fed. Reg. at 34,474.

Even assuming, for the sake of argument, that it were permissible for EPA to base its BAT determination on the compliance costs to individual coal-burning power plants as opposed to the steam electric generating industry as a whole, Option 4a rests on nothing more than EPA's unsupported "belief" that "companies may choose to shut down 400 MW and smaller units instead of making new investments to comply with proposed zero discharge bottom ash requirements."[491] EPA bases this "belief" on its claim that units 400 MW or less represent over 90 percent of announced retirements.[492] But EPA has conducted no analysis to show that the incremental cost of a zero discharge standard for bottom ash transport water would compel additional units to retire. EPA has simply assumed that since some smaller units have retired, other smaller units that have not retired are nevertheless so economically vulnerable that the cost of converting to dry handling for bottom ash transport water would compel many of them to retire as well, despite evidence that O&M costs would actually decrease. This sort of unsupported belief falls far short of the reasoned decision-making required by the APA and the Clean Water Act.[493]

Moreover, EPA's "belief" is contradicted by the evidence in the record showing that a zero discharge bottom ash standard would cause a negligible increase in retirements. While EPA did not model the retirement impacts of Option 4a, EPA did model Option 4, which includes a zero discharge bottom ash transport water standard for all plants greater than 50 MW.[494] Option 4 would lead to a net increase in retirements of 317 MW, or 0.1 percent of total industry capacity.[495] And that modeling shows the effect of imposing compliance costs on several waste streams other than bottom ash, such as fly ash and FGD wastewater, so the modeling overstates the impact of a zero discharge standard for bottom ash. In other words, the net incremental retirements from a zero discharge bottom ash standard must be less than 317 MW of retirements. Even using this counterfactual, conservative analysis, EPA estimates that the net loss of capacity would amount to the equivalent of a single 317 MW unit. EPA's "belief" that a zero discharge standard for bottom ash would cause a wave of retirements at smaller units is thus contradicted by its own data.

Finally, even if EPA were correct that a zero discharge standard would cause some small plants to retire early, that would not justify less stringent BAT limits for units smaller than 400 MW. EPA has approved BAT and BPT limits that the Agency expected would cause plants to close.[496] Courts have consistently upheld these rules.[497]

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[491] 78 Fed. Reg. at 34,470.
[492] *Id.*
[493] *See generally Am. Meat Inst. v. EPA*, 526 F.2d 442, 464-65 (7th Cir. 1975) (EPA's decisions must be supported by adequate evidence in the record); *see also Chem. Mfr. Ass'n*, 870 F.2d at 251 (EPA must establish a reasonable basis in the record for its decision).
[494] 78 Fed. Reg. at 34,458, 34,498.
[495] 78 Fed. Reg. at 34,498.
[496] 65 Fed. Reg. 81,242, 81,276 (Dec. 22, 2000) (12.5% of facilities in the metals subcategory expected to close as a result of BAT limits); 52 Fed. Reg. 42,522, 42,551 (Nov. 5, 1987) (4% of chemicals manufacturing facilities expected to close as a result of BAT limits); 69 Fed. Reg. 51,892, 51,919 (Aug. 23, 2004) (3.4% or 2.9% of commercial concentrated aquatic animal production facilities expected to close as a result of new BPT and BAT requirements, depending on the forecasting method used); 47 Fed. Reg. 52,848, 52,858-59 (Nov. 23, 1982) (1.3% of wet tanning plants expected to close as a result of BAT and BCT limits, and 1.9%-3.1% of wet tanning plants expected to close as a result of the entire rule, which included BAT, BCT, BPT, and PSES limits); 63 Fed. Reg.

Courts have emphasized that the plain text of the Act requires EPA to establish BAT limits for categories of sources rather than on a plant by plant basis, and therefore BAT limits should be based on a consideration of costs to the industry rather than the compliance cost for an individual plant.[498] Furthermore, Congress envisioned technology-based limits as spurring the rest of each industry to catch up to the model plants using the most effective pollution controls. The Clean Water Act's technology-based limits require firms to meet at the top, rather than race to the bottom based on the performance of the least-efficient plants.[499]

Adopting a 400 MW threshold based on concerns that some individual plants will have high compliance costs is inconsistent with the statutory command to set BAT limits for broad categories of sources, and inconsistent with the statutory instruction to consider costs for the industry as a whole, rather than for individual plants. Given the text and legislative history of the Act, EPA should not set more lenient limits for all plants smaller than 400 MW based on an unsubstantiated belief that some plants might have disproportionately high compliance costs.

2. The 400 MW threshold is based on inflated cost estimates.

The 400 MW threshold is arbitrary for the additional reason that it is based on cost estimates that are greatly exaggerated. As explained above, EPA overestimated the cost of converting units to zero discharge systems for handling bottom ash. In calculating the costs of units converting to zero discharge systems for bottom ash handling, EPA failed to account for economies of scale; included costs for units that will retire or convert in the absence of the rule; overestimated operating and maintenance costs; and used an artificially high annualization factor. Given that the costs of meeting a zero discharge standard are substantially lower than EPA has estimated, the impacts to smaller units will also be far less than EPA has estimated.

EPA assumes that there are 125 units equal to or less than 400 MW that would cost $1.9 billion in capital and $239 million per year to convert to zero discharge systems– this is an average of

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18,504, 18,550 (Apr. 15, 1998) (2.3% of the mills in the Bleached Papergrade Kraft and Soda subcategory expected to close as a result of BAT and PSES requirements); 48 Fed. Reg. 49,126, 49,134-35 (Oct. 24, 1983) (2% of aluminum forming plants expected to close as a result of BPT and PSES limits).

[497] *See, e.g.*, *Am. Paper Inst. v. Train*, 543 F.2d 328 (D.C. Cir. 1976) (upholding BPT guidelines that EPA projected would cause 7-10 out of 188 paper mills to shut down); *Ass'n of Pac. Fisheries,* 615 F.2d at 808-09 (upholding BPT limits that EPA estimated would cause 33% of non-remote Alaskan salmon canning facilities to close and would cause 57% of non-remote Alaskan fresh and frozen salmon facilities to close); *Weyerhaeuser,* 590 F.2d at 1047 (rejecting challenges to effluent guidelines that EPA estimated would cause 8 plants to close); *Chem. Mfrs. Ass'n,* 870 F.2d at 250-51 (upholding as reasonable effluent guidelines that EPA stated might cause 14% of indirect dischargers to close).

[498] *EI DuPont v. Train,* 430 U.S. 112, 127, (1977); *Waterkeeper Alliance v. EPA,* 399 F.3d 486, 516 (2d Cir. 2005); *Rybachek v. EPA,* 904 F.2d 1276, 1290-91 (9th Cir. 1990); *Am. Iron & Steel Inst. v. EPA,* 526 F.2d 1027 (3d. Cir. 1975).

[499] *See Weyerhaeuser v. Costle*, 590 F.2d 1011, 1037 (D.C. Cir. 1978) ("Most prominently, the Act's supporters in both Houses acknowledged and accepted the possibility that its 1977 requirements might cause individual plants to go out of business. . . They self-consciously made the legislative determination that the health and safety gains that achievement of the Act's aspirations would bring the future generations will in some cases outweigh the economic dislocation it causes to the present generation."); *Chem. Mfrs. Ass'n,* 870 F.2d at 252 ("Congress clearly understood that achieving the CWA's goal of eliminating all discharges would cause 'some disruption in our economy,' including plant closures and job losses.").

$23 million in capital costs and $2.1 million in operating and maintenance costs per year, which is inconsistent with real world experience.[500] Those figures are closer to the costs for retrofitting a plant with *two* units just under the 400 MW threshold. For example, when the Wateree plant retrofit two 372 megawatt units, each unit was converted to a zero discharge bottom ash system for $11.25 million in capital costs and between $800,00 and $1.5 million per year in operating costs, well below EPA's estimates.[501] Several other units equal to or smaller than 400 MW have converted to zero discharge systems, suggesting that the cost of meeting a zero discharge standard can be borne by plants equal to or less than 400 MW. South Carolina Electric & Gas Company retrofit two 125 MW units in 2008; the BL England station retrofit a 125 MW, 155 MW, and 170 MW units in 2010; 2012, the Coronado generating station retrofit two 400 MW units in 2012.[502]

In short, the proposed 400 MW threshold is based on EPA's assumption that the cost of zero discharge systems is disproportionately high for smaller units and will drive smaller units to retire early. These conclusions rely on artificially high estimates of the cost to convert to zero discharge systems. EPA's assertion that smaller units cannot afford such controls cannot rest on such faulty cost estimates, and EPA should find that a zero discharge standard for all units is economically achievable.

VI. EPA FAILED TO CONSIDER CHEMICAL PRECIPITATION FOLLOWED BY MECHANICAL EVAPORATION AS BAT FOR COMBUSTION RESIDUAL LEACHATE. AT A MINIMUM, BAT FOR COMBUSTION RESIDUAL LEACHATE IS CHEMICAL PRECIPITATION FOLLOWED BY BIOLOGICAL TREATMENT FOR ALL PLANTS.

EPA should set BAT limits for combustion residual leachate based on chemical precipitation followed by biological treatment for all plants. As a preliminary matter, EPA underestimated loadings from combustion residual leachate by failing to account for leachate from surface impoundments; leaks and seeps from impoundments; and groundwater with a hydrogeological connection to surface waters.[503] The public health and environmental impacts from leachate are significant, and many of EPA's proven or potential coal ash damage cases were caused by leachate.[504] Thus, EPA should set BAT limits to prevent these discharges instead of maintaining the status quo as proposed under all of the Agency's preferred options.

The characteristics of leachate and FGD wastewater are similar, and many of the same treatment technologies that are appropriate for FGD wastewater are also appropriate for leachate. Yet EPA failed to consider chemical precipitation plus mechanical evaporation as BAT for leachate. At a minimum, EPA should have set BAT limits based on chemical precipitation plus biological treatment because this treatment system is both technologically available and economically achievable. In the alternative, chemical precipitation is BAT for leachate. For these reasons, maintaining the status quo (i.e., impoundments) is not BAT.

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500 Fox Report, Appendix E, at 16.
501 EPA, Final Draft of Wateree Site Visit Notes at 5, 8, Docket No. EPA-HQ-LW-2009-0819-1917.
502 Fox Report, Appendix E, at 19-20.
503 TDD at 10-19.
504 *See* EA at A-11-A-39.

A. EPA UNDERESTIMATED LOADINGS FROM COMBUSTION RESIDUAL LEACHATE.

EPA systematically underestimates combustion residual leachate loadings and impacts to public health and the environment by only estimating leachate loadings from landfills. EPA failed to account for leachate loadings from (1) surface impoundments, (2) leaks and seeps from impoundments into surface waters, and (3) leaks and seeps from impoundments and landfills to groundwater with a hydrogeological connection to surface water. EPA proposes to define combustion residual leachate as

> leachate from landfills or surface impoundments containing residuals from the combustion of fossil or fossil-derived fuel. Leachate includes liquid, including any suspended or dissolved constituents in the liquid, that has percolated through or drained from waste or other materials placed in a landfill, or that pass through the containment structure (e.g., bottom, dikes, berms) of a surface impoundment. Leachate also includes the terms seepage, leak, and leakage, which are generally used in reference to leachate from an impoundment.[505]

Despite this broad definition, EPA fails to account for all loadings of combustion residual leachate and only estimates loadings from landfills directly to surface waters.[506] These omissions are significant, especially since EPA minimizes public health and environmental impacts from leachate due to comparatively smaller loadings in relation to FGD and ash transport water wastestreams.[507]

First, EPA does not estimate baseline or post-compliance surface impoundment leachate loadings because "EPA determined that combustion residual impoundments will recycle the leachate back to the impoundment from which it was collected rather than install the technology basis for the discharge requirements."[508] Based on this, EPA "finds that baseline and post-compliance pollutant loadings will be the same at baseline and at post-compliance for combustion residual leachate."[509] But EPA's logic is flawed; the fact that industry will choose to recycle collected leachate back to an impoundment if faced with stringent discharge limits does not mean that all impoundments currently send leachate back to impoundments in the absence of discharge limits. In fact, only 36% of plants that collect impoundment leachate recycle the leachate back to the impoundment.[510]

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[505] 78 Fed. Reg. at 34,533.
[506] TDD at 10-19.
[507] *See* TDD at 8-32 (EPA chose not to propose chemical precipitation—a technologically available and economically achievable—as BAT because "[t]he record demonstrates that the amount of pollutants collectively discharged in leachate by steam electric plants is a very small portion of the pollutants discharged collectively for all steam electric power plants (i.e., less than ½ a percent).").
[508] TDD at 10-19.
[509] *Id.*
[510] *Id.* at 7-40.

Leachate loadings from surface impoundments are significant. EPA states that impoundments generate approximately 4 billion gallons of leachate each year compared to 2.2 billion gallons from landfills.[511] EPA estimates that, on average, each plant with impoundments generates 236,000 gallons of toxic-laden leachate every day.[512] Currently, only about half of the total impoundment leachate generated is returned to the impoundment or recycled, which means that approximately 2 billion gallons of impoundment leachate is currently discharged to surface waters each year.[513] In addition, industry's own sampling data show that impoundment leachate—like landfill leachate—contains high concentrations of metals and other pollutants, "similar to FGD and ash wastewaters."[514] In some cases, average concentrations of pollutants in untreated impoundment leachate are higher than concentrations in untreated landfill leachate.[515] For example, average concentrations of cadmium in impoundment leachate are 5.1 µg/l compared to .73 µg/l in landfill leachate.[516] The average selenium concentration in leachate from impoundments is 152 µg/l where the landfill leachate is only 46 µg/l.[517] Yet EPA failed to account for impoundment leachate loadings in the combustion residual leachate baseline loadings estimate and expected reductions estimates as a result of BAT requirements.[518]

Second, EPA does not account for loadings from leaks and seeps directly to surface waters from impoundments.[519] For example, engineers have estimated that an impoundment containing coal ash and FGD waste at the Progress Energy Asheville coal-burning power plant in North Carolina may be leaking at a rate of up to *1 million gallons per day*.[520] In addition, the Tennessee Valley Authority collects seepage from one ash pond at the Colbert coal-burning power plant.[521] According to EPA's Enforcement and Compliance History Online (ECHO) database, the average maximum discharge of the collected seepage from Ash Pond 4 is 0.125 million gallons per day, or approximately 46 million gallons per year.[522] Based on concentrations reported in the most recent NPDES application, seeps from the Colbert Ash Pond 4 dump 1,447 pounds of boron,

[511] *Id.* at 6-13.
[512] *Id.*
[513] *Id.* at 6-14.
[514] *Id.* at 6-16.
[515] *Compare id.* at 6-15 tbl. 6-10 *with id.* at 6-16 tbl. 6-11.
[516] *Id.*
[517] *Id.*
[518] TDD at 10-19.
[519] EPA states that its estimates of baseline landfill leachate loadings includes leaks and seeps from landfills because EPA assumed the volumes reported by facilities in response to the 2010 Questionnaire included leaks and seeps based on the definition of leachate. Email from Jezebele Alicea, U.S. Envtl. Prot. Agency, to Jennifer Duggan, Envtl. Integrity Project (Sept. 13, 2013).
[520] *See* Report from Daniel S. McGough, et al., S&ME, Inc. to Bill Forster, Progress Energy Carolinas, Inc. Re 1964 Ash Basin Dam Improvements at the Progress Energy Asheville Plant (Project No. 1411-10-083) 10-11 (June 24, 2011).
[521] Tennessee Valley Authority, Application for Renewal of NPDES Permit No. AL0003867 for the Colbert Fossil Plant (Nov. 20, 2009).
[522] The average flow is calculated from reported flow during June 2008 through December 2012. *See* U.S. Envtl. Prot. Agency, Enforcement and Compliance History Online (ECHO), http://www.epa-echo.gov/echo. This may be a conservative estimate, as the most recent NPDES application states that flow from this outfall is .232 million gallons per day. Tennessee Valley Authority, Application for Renewal of NPDES Permit No. AL0003867 for the Colbert Fossil Plant (Nov. 20, 2009).

64,726 pounds of sulfates, and 876 pounds of manganese into Cane Creek each year.[523] And this represents only a fraction of the seepage at the Colbert plant because some of the seepage flows directly into Cane Creek.[524]

These are just two examples to highlight that the loadings from leaks and seeps are not zero, as EPA has assumed. There are at least 1,070 coal plant impoundments in the United States, many of which are prone to leaks and seeps.[525] Leaks and seeps from impoundments into ground and surface waters are a widespread problem that EPA and state regulators have long overlooked. Because these discharges are not typically identified in the plant's NPDES permit, they may continue unabated for years before they are even discovered by regulators or concerned citizens who visibly observe brightly colored water emanating from riverbanks. Over the last two years, teams from Waterkeeper Alliance have inspected coal plant impoundments at 17 power plants in five Southeastern states. Of these plants, the Waterkeeper teams identified 12 plants[526] where impoundments were seeping toxic pollutants into nearby surface waters. The Waterkeeper teams discovered seeps at every single plant they investigated in the state of Alabama. In North Carolina, the threat of citizen enforcement actions at Duke Energy's Riverbend Steam Station and Asheville Steam Plant prompted the state to file its own suite of enforcement actions, alleging surface and groundwater contamination from leaking impoundments at every one of the 14 coal-burning power plants in the state.[527] In spite of the ease with which the Waterkeeper teams were able to identify a great many seeps, EPA Region 4 Water Division staff were generally unaware of the extent to which these discharges were occuring until January 2013.[528] EPA must account for these leaks and seeps that discharge directly to surface waters in the final rule.

Finally, EPA fails to include leachate loadings to groundwaters that have a hydrogeological connection to surface waters. Discharges of pollution to groundwaters that flow into surface

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[523] Tennessee Valley Authority, Application for Renewal of NPDES Permit No. AL0003867 for the Colbert Fossil Plant (Nov. 20, 2009).
[524] *See* Tennessee Valley Authority, Colbert Fossil Plant Groundwater Assessment 17 (1994) ("Highly conductive zones were also measured in a muddy area between Cane Creek and the eastern berm of Ash Pond 4. Because the survey was conducted after a period of dry weather, and the liquid in both ponds is highly conductive, these two anomalies might be attributable to leachate from Ash Pond 4 and the coal yard drainage basin."). *See also id.* at 25 (nothing that there is a groundwater mound beneath Ash Pond 4 that causes seepage along the bank of Cane Creek).
[525] 78 Fed. Reg. at 34,516.
[526] The fact that seeps were not visible at five of the 17 plants inspected by Waterkeepers does not necessarily mean that the impoundments at those plants are not leaking. Citizen investigations are limited to the areas around plants with public access (i.e. along public waters or roads). It is quite possible that leaks and seeps are occurring at the plants in areas where the public does not have access to or underground where they could not be observed.
[527] *See* Complaints filed by the North Carolina Dep't of Env't and Natural Res. against various Duke Energy entities, *available at*
http://portal.ncdenr.org/web/wq/hot-topics/asheville_riverbend_steamstadocs
– and –
http://portal.ncdenr.org/web/wq/hot-topics/duke_energy_aug2013injunctions
(last visited Sept. 12, 2013).
[528] Ten Riverkeepers from Alabama, Georgia, Florida, and North Carolina had a telephone conference with Region 4 Water Division staff (arranged by Karrie-Jo Shell, EPA) at 12:30 p.m. on Jan. 15, 2013. The Riverkeepers each described in detail illicit CCR seepage discharges that were occurring in the watersheds they patrol.

waters are within the scope of the Clean Water Act,[529] and EPA must account for these loadings and environmental impacts in this rule. As EPA acknowledges, several coal combustion waste sites have polluted surface waters from discharges of leachate to groundwater.[530] Yet EPA does not account for this pollution in loadings estimates,[531] nor does EPA "quantify the environmental and human health impacts resulting from pollutants leaching into the ground water from coal combustion residuals . . . surface impoundments and landfills."[532] Thus, EPA's baseline loadings do not accurately reflect the amount of leachate entering the environment from coal plants. EPA should account for these additional loadings in the baseline loadings for combustion residual leachate.

B. COAL COMBUSTION RESIDUAL LEACHATE HAS SIGNIFICANT, ADVERSE IMPACTS ON PUBLIC HEALTH AND THE ENVIRONMENT.

Coal combustion residual leachate is responsible for significant, adverse impacts on public health and the environment. Even though total leachate loadings may be small in relation to FGD and ash transport wastewaters, impoundments and landfills often directly discharge or leak and seep into groundwater and/or smaller creeks and streams that are tributaries of larger rivers and lakes. Toxic pollution in small streams and creeks will result in higher concentrations of selenium, cadmium, and other pollutants that are toxic to aquatic life in minute concentrations. In addition, humans recreating in and around these smaller water bodies will also face a greater risk of adverse health effects from exposure to higher concentrations of coal combustion waste pollution.

In fact, combustion residual leachate is responsible for a significant number of EPA proven and potential damage cases. Nearly half (30 of 67) of EPA's documented surface water damage cases were caused by leachate seeping into groundwater flowing into surface water.[533] For all these reasons, it is critical that EPA set BAT limits based on chemical precipitation followed by biological treatment to clean up these dangerous discharges and protect public health and the environment.

C. COMBUSTION RESIDUAL LEACHATE HAS SIMILAR CHARACTERISTICS TO FGD WASTEWATERS.

EPA notes that the average untreated leachate concentrations[534] reported by industry in response to EPA's 2010 Information Collection Request and the average untreated FGD wastewater

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[529] *See, e.g.*, *Hernandez v. Esso Standard Oil Co.*, 599 F.Supp.2d 175, 181 (D. Puerto Rico 2009) (reviewing federal case law and holding "that the CWA extends federal jurisdiction over groundwater that is hydrologically connected to surface waters that are themselves waters of the United States").
[530] EA at 4-21.
[531] *See* TDD at 10-19; EA at 4-21.
[532] *See* EA at 4-21 (acknowledging that the EA "may therefore underestimate the number of exceedances occurring at immediate receiving waters").
[533] EA at A-29-A-39.
[534] EPA defines leachate broadly under the ELG rule. *See* 78 Fed. Reg. at 34,533. We note that the untreated and treated leachate data collected by industry for purposes of regulating surface water discharges must not be used to replace data acquired by the scientific method to specifically characterize the compositional variability and diversity of environmental releases from CCR disposal units to assess health and environmental risks pursuant to RCRA.

concentrations from EPA sampling have similar characteristics although concentrations of most pollutants in leachate are lower.[535] The chart below, taken from average concentration and flow data from the TDD, demonstrates this.

Table 4 – Comparison of Average Concentrations of Untreated FGD Wastewater and Combustion Residual Landfills

	Untreated FGD Wastewater	Untreated Impoundment Leachate	Untreated Landfill Leachate		
	Average Total	Average Total	Average Total Active	Average Total Inactive	Average Total Retired
Metals (µg/l)					
Aluminum	332,000	213	5030	100	87
Antimony	22	0.96	4.6	4.9	1.1
Arsenic	489	20	46	10	41
Barium	2,850	55	57	50	37
Beryllium	17	0.51	1.9	0.47	1.1
Boron	291,000	22,800	20,500	3,640	10,100
Cadmium	159	5.1	2.7	1.9	0.73
Calcium	3,250,000	291,000	481,000	386,000	303,000
Chromium	1,300	1.8	4.9	1.6	3.4
Chromium (VI)	NA				
Cobalt	310	8.1	84	3.8	7.6
Copper	784	2.7	10	1.7	2.4
Iron	764	7,070	59,000	95	5,700
Lead	323	0.51	1.4	0.47	0.83
Magnesium	3,630,000	123,000	115,000	33,700	21,800
Manganese	107,000	2,170	4,360	355	1,280
Mercury	411	0.19	1.4	0.01	13
Molybdenum	313	208	1,880	995	702
Nickel	1,880	21	69	43	16
Selenium	4,490	152	74	84	46
Silver	9	0.63	0.68	0.42	1.03
Sodium	275,000	145,000	327,000	16,700	66,200
Thallium	27	0.67	1.3	0.96	0.92
Tin	184	105	11	13	33
Titanium	4,840	7.1	17	15	11
Vanadium	1,450	3.9	3,240	6.2	69
Zinc	5,380	301	154	58	38
Classicals (µg/l)					
Ammonia	6,350				
Nitrate Nitrite as N	74,900				
Nitrogen, Total Kjeldahl	39,600				
Biochemical Oxygen Demand	9,380.00				
Chemical Oxygen Demand	367,000				
Chloride	7,740,000	251,000	542,000	11,100	149,000
Sulfate	8,140,000	1,242,000	1,910,000	1,070,000	881,000
Cyanide, Total	764				
Total Dissolved Solids	28,600,000	2,380,000	3,860,000	1,670,000	1,660,000
Total Suspended Solids	16,800,000	9,230	414,000	4,210	13,800
Phosphorous, Total	3,190				

Specifically, there is a critical distinction between pore water (which was not collected or analyzed for the ELG rulemaking) and leachate. *See* discussion *infra* re: CCR-Risk Assessment-ELG Chemical Data.

[535] TDD at 7-39.

Thus, many of the same treatment technologies appropriate for FGD wastewater (i.e., chemical precipitation, chemical precipitation followed by biological treatment, chemical precipitation followed by evaporation) are also appropriate for removing metals and other pollutants in leachate from landfills and surface impoundments.

D. EPA FAILED TO CONSIDER CHEMICAL PRECIPITATION PLUS EVAPORATION AS BAT FOR COMBUSTION RESIDUAL LEACHATE.

EPA should have considered chemical precipitation plus evaporation as BAT for leachate. A technology is "available" where EPA has evidence that its use is practicable within the relevant industry. "That no plant in a given industry has adopted a pollution control device which could be installed does not mean that the device is not 'available.'"[536] A discharger may be required to use superior treatment technologies that have been demonstrated in another context if a technology transfer is practicable.[537] In this case, EPA has "determined that combustion residual leachate from landfills and impoundments includes similar types of constituents as FGD wastewater," although concentrations of the pollutants in leachate are "generally lower than FGD wastewater."[538] Thus, EPA should have considered chemical precipitation plus evaporation as BAT for leachate.

The record does not include any evidence to suggest that it is not technologically feasible or economically achievable to eliminate, or at least significantly reduce, toxic pollution in combustion residual leachate using a chemical precipitation plus mechanical evaporation system. As the record makes clear, the characteristics of leachate and FGD wastewater are similar, except that concentrations of most of the pollutants are lower in leachate. In fact, treating leachate and FGD wastewater or leachate alone in this type of system may actually act to improve performance by diluting the concentration of salts and other pollutants.[539] Thus, EPA should not have dismissed chemical precipitation plus evaporation for treatment of leachate out of hand.

E. AT A MINIMUM, CHEMICAL PRECIPITATION PLUS BIOLOGICAL TREATMENT IS BAT FOR LEACHATE AT ALL PLANTS.

Chemical precipitation plus biological treatment is both technologically available and economically achievable to remove metals and other pollution from combustion residual leachate. None of the other factors in section 304(b)(2)(B) alters the conclusion that BAT limits should be based on chemical precipitation plus biological treatment for all plants. Thus, EPA should set BAT limits for leachate based on this treatment technology.

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[536] *Hooker Chems. & Plastics Corp. v. Train*, 537 F.2d 620, 636 (2d Cir. 1976).

[537] *See, e.g.*, *Tanner's Council of Am. v. Train*, 540 F.2d 1188, 1192 (4th Cir. 1976) (holding that transfer is permissible if the technology can be practicably applied); *see also Reynolds Metals Co. v. EPA*, 760 F.2d 549, 562 (4th Cir. 1985) (treatment technology from aluminum forming industry was transferable to can-making industry).

[538] TDD at 7-39. *See also* Jenkins Leachate Report, Appendix D.

[539] *See* Section III.A.1 (noting that FGD wastewater requires pretreatment due to concentrated nature of the blowdown streams and high concentrations of metals and other pollutants).

1. Chemical precipitation plus biological treatment is technologically available.

EPA's record demonstrates that chemical precipitation plus biological treatment is technologically available for plants operating FGD systems. The record shows that at least one plant, AEP's Mountaineer Plant in West Virginia, is treating combustion landfill leachate in an anaerobic biological reactor.[540] Furthermore, a technology is "available" where EPA has evidence that its use is practicable within the relevant industry. "That no plant in a given industry has adopted a pollution control device which could be installed does not mean that the device is not 'available.'"[541] A discharger may be required to use superior treatment technologies that have been demonstrated in another context if a technology transfer is practicable.[542] In this case, EPA has "determined that combustion residual leachate from landfills and impoundments includes similar types of constituents as FGD wastewater," although concentrations of the pollutants in leachate are "generally lower than FGD wastewater."[543] Thus, some of the same treatment technologies available for FGD wastewater—including chemical precipitation and biological treatment—are also available to treat leachate.[544]

The record supports EPA's determination that "[p]hysical/chemical treatment systems are capable of achieving low effluent concentrations of various metals and are effective at removing many of the pollutants of concern present in leachate discharges to surface waters."[545] Yet chemical precipitation alone "is not effective at removing selenium, boron, and certain other parameters that contribute to total dissolved solids (e.g., magnesium, sodium)" in leachate.[546] However, the addition of biological treatment can remove these pollutants from leachate similar to FGD wastewater and is BAT.[547]

At least one plant is already treating leachate with chemical precipitation and biological treatment with its FGD wastewater. The AEP Mountaineer plant in West Virginia operates and ABMet system that handles FGD wastewater and landfill leachate.[548] Influent and effluent data for this plant demonstrate that the plant can reliably meet the selenium and mercury limits proposed by EPA for biological treatment systems for FGD wastewaters.[549] In fact, the Mountaineer plant achieves even sharper mercury reductions than plants operating two-stage chemical precipitation.[550]

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[540] *See* ERG Memo, Status of Biological Treatment Systems to Remove Selenium (April 19, 2013), EPA-HQ-OW-2009-0819-2127.
[541] *Hooker Chems. & Plastics Corp.*, 537 F.2d at 636.
[542] *See, e.g.*, *Tanner's Council of Am.*, 540 F.2d at 1192 (holding that transfer is permissible if the technology can be practicably applied); *see also Reynolds Metals Co. v. EPA*, 760 F.2d 549, 562 (4th Cir. 1985) (treatment technology from aluminum forming industry was transferable to can-making industry).
[543] TDD at 7-39.
[544] *Id.*
[545] TDD at 8-13.
[546] TDD at 8-13.
[547] *See, e.g. id.* At 7-9-7-10.
[548] *See* ERG Memo, Status of Biological Treatment Systems to Remove Selenium (April 19, 2013), EPA-HQ-OW-2009-0819-2127; Section III.B.4. *supra*.
[549] Section III.B.4. *supra*.
[550] *Id.*

EPA statements in the record also indicate that leachate can be treated with FGD wastewater with chemical precipitation and biological treatment.[551] For example, in determining compliance costs, EPA notes that plants required to use biological treatment to clean up FGD wastewaters will treat leachate and FGD wastewater in a single system (even though biological treatment is not necessary to meet leachate limits) because it would be more expensive to treat the two wastewater streams separately.[552]

As the attached report of David Jenkins states, the general result of combining untreated impoundment leachate with FGD wastewater is to dilute the concentrations of metals and other pollution.[553] This will make it easier for plants to comply with EPA's proposed effluent limitations for FGD wastewaters for selenium and mercury.[554] In addition, "the dilution of 'matric' components such as 'salt' (TDS, sulfate, chloride) will be beneficial to the anaerobic treatment processes."[555] Although plants will have to install adequate equalization upstream of the biological systems to account for intermittent flows and/or variable composition and regulate temperature, a closely monitored and well-operated chemical and biological treatment system could achieve the effluent limits EPA proposes for selenium and mercury.[556]

Chemical precipitation plus biological treatment is also technologically available to treat leachate at plants that don't have wet FGD systems. EPA dismissed this treatment option out of hand without a robust analysis. EPA's stated rationale for rejecting chemical precipitation plus biological treatment is that "leachate flows can be more variable than FGD wastewater and, more importantly, *may* be too intermittent to facilitate reliable and consistent biological treatment. Such variations are easily accommodated in a chemical precipitation treatment system, but *may* be difficult to manage in a biological treatment system reliant on healthy and sustainable populations of microorganisms."[557] EPA presents no data concerning the intermittency of these waste streams, only daily average flows. Further, there is no apparent reason why leachate from an impoundment would normally be intermittent because precipitation is not needed to create leachate flow, as it would be for a landfill. In fact, any difficulties treating leachate in a biological treatment system can be easily managed with temperature regulation and collection tanks to store leachate and ensure a steady flow into the system.[558]

At least one coal-burning power plant currently uses a chemical treatment and biological system for leachate,[559] and coal plants have successfully utilized this technology to clean up discharges of FGD wastewater,[560] which has a similar composition to impoundment and landfill leachate.[561]

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[551] TDD at 9-41 n.84.
[552] *Id. See also* U.S. Envtl. Prot. Agency, Incremental Costs and Pollutant Removals for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category 9-1 (Apr. 2013).
[553] See Jenkins Leachate Report, Appendix D.
[554] *Id.*
[555] *Id.*
[556] *Id.*
[557] TDD at 8-13 (emphasis added).
[558] *See* Jenkins report at 5 (noting that similar concerns with biological systems treating both FGD and leachate can be easily managed through equalization and collection tanks and temperature regulation).
[559] *See* ERG Memo, Status of Biological Treatment Systems to Remove Selenium (April 19, 2013), EPA-HQ-OW-2009-0819-2127; Section III.B.4. *supra*.
[560] TDD at 7-40; Section III.B *supra*.

In addition, the removal of metals and other pollutants found in leachate "using chemical precipitation technology is also demonstrated by technical information compiled for ELGs promulgated for other industry sectors."[562] For example, during the rulemaking to establish ELGs for the Landfills Point Source Category, EPA estimated that even prior to promulgation of the new rules "33 percent of indirect hazardous landfills, 5 percent of indirect non-hazardous waste landfills, and 9 percent of direct non-hazardous landfill facilities employ chemical precipitation as part of wastewater treatment systems" to remove metals.[563] Thus, chemical precipitation plus biological treatment to clean up leachate discharges from power plants is technologically available.

2. *Chemical precipitation plus biological treatment is economically achievable.*

Chemical precipitation plus biological treatment is economically achievable. As discussed in greater detail elsewhere, the costs of Option 4 and 5 can be reasonably borne by the utility industry.[564] Because EPA did not evaluate chemical precipitation followed by biological treatment costs as part of any of the options, Commenters estimated the costs of Option 4 with this technology. Specifically, Commenters subtracted EPA's estimates for industry level compliance with chemical precipitation from Option 4 and added EPA's estimates for compliance with chemical precipitation plus biological treatment in the TDD to calculate Option 4 costs with chemical precipitation plus biological treatment as BAT for leachate. Substituting EPA's estimates for industry level compliance with chemical precipitation plus biological treatment for leachate in Option 4 results in only a marginal increase in total compliance costs under Option 4 and is significantly lower than costs under Option 5.[565]

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[561] TDD at 7-39.

[562] TDD at 8-13 (citing the TDDs for Landfills Point Source Category and Metal Products and Machinery Point Source Category).

[563] *See* U.S. Envtl. Prot. Agency, Development Document for Final Effluent Limitations Guidelines and Standards for the Landfills Point Source Category (EPA-821-R-99-019) 8-10 (Jan. 2000).

[564] *See infra* Section IX.

[565] Commenters could not estimate costs for chemical precipitation followed by biological treatment for leachate under Option 5. EPA states that "[f]or plants where EPA calculated costs for the treatment of FGD wastewater and combustion residual landfill leachate in the same system, EPA is presenting the incremental increase in the cost of the treatment system compared to the treatment of only FGD wastewater (i.e., the cost of treating FGD wastewater alone was subtracted from the cost of treating the combined wastestreams)." RIA at 9-42. Thus, the compliance costs for chemical and biological treatment for leachate assume that plants with FGD systems will operate the same system whereas Option 5 requires mechanical operation for FGD wastewaters. As discussed above, EPA should evaluate whether chemical precipitation followed by mechanical evaporation is BAT for leachate.

Table 5 – Estimated Industry-Level Costs (in millions of 2010 dollars)[566]

Regulatory Option	Capital Costs	Annual O&M Costs	Recurring Costs	
			6-year	10-year
Option 4	8,011	988	16	(137)
Option 4 (chem+bio)	8,327	1,009	16	(137)
Option 5	11,755	1,753	19	(137)

EPA does not provide a detailed analysis of the economic achievability of chemical precipitation or chemical precipitation followed by biological treatment as BAT in terms of a single wastestream, noting only that "EPA also looked at the cost effectiveness of controlling leachate using chemical precipitation and this value would exceed $1,000 per TWPE removed."[567] However, EPA likely overestimates this value. As discussed above, EPA has underestimated baseline loadings of leachate because it fails to take into account loadings associated with approximately 2 billion gallons of impoundment leachate; leaks and seeps from impoundments and landfills; and polluted groundwater with a hydrogeological connection to surface waters.[568] Failing to account for all loadings in the baseline skews the cost-effectiveness value high because the post-compliance loadings will not account for the true number of pounds of pollution removed.[569] In any event, the record demonstrates that the utility industry can afford Option 5. Therefore, chemical precipitation plus biological treatment is economically achievable.

The other factors set forth in section 304(b)(2)(B) do not alter the conclusion that BAT limits should be set for leachate based on chemical precipitation followed by biological treatment for the same reasons discussed in Section III.B.3. The plant's age's is irrelevant to the ability to operate chemical precipitation and biological treatment systems.[570] Chemical and biological treatment systems can be scaled up or down so the size of the plant is not relevant.[571] Space will not be an issue at the vast majority of these plants because the infrastructure for chemical and biological treatment systems is a series of connected tanks and the footprint is small, especially compared to massive impoundments currently used to manage waste at coal plants.[572] For example, the Roxboro plant's systems, which has the largest flow of any scrubber with an ABMet system, takes up less than one acre.[573] EPA's record also supports the conclusion that

566 78 Fed. Reg. at 34,485; TDD at 9-42.
567 TDD at 8-34 n. 59.
568 *See* discussion *supra*.
569 Only 36% of impoundments currently recycle all wastewater back to the impoundment. EPA suggests that all plants with impoundments will not incur leachate treatment costs as a result of Option 4 and 5 because they will choose to recycle all wastewater back to the impoundment, Thus, EPA has failed to account for the fact that these Options would reduce about 2 billion gallons of toxic wastewater from entering surface waters at no cost.
570 *See* discussion in Section III.B.3 *supra*.
571 *Id.*
572 *Id.*
573 *Id.*

non-water environmental impacts are minimal and do not weigh against chemical precipitation and biological treatment as BAT for leachate.[574] Thus, chemical precipitation followed by biological treatment is BAT for leachate.

F. IN THE ALTERNATIVE, CHEMICAL PRECIPITATION IS BAT FOR LEACHATE.

In the alternative, BAT for combustion residual leachate is chemical precipitation. For the reasons discussed above, chemical precipitation is both technologically available and economically achievable for the removal of certain types of metals in leachate. Because EPA based the effluent limits for leachate on FGD wastewaters, FGD wastewaters share similar characteristics with leachate based on the data collected by EPA for the ELG rulemaking, and FGD wastewaters generally have higher concentrations of metals and other pollutants, the effluent limits for leachate based on chemical precipitation are achievable. In fact, these limits may be too lenient as concentrations of metals were generally higher in the FGD wastewater samples EPA collected than concentrations in leachate data collected as part of this rulemaking. Thus, at a minimum, chemical precipitation is BAT for leachate.

G. SETTING BAT LIMITS BASED ON AN IMPOUNDMENT IS NOT SUPPORTED BY THE RECORD.

Even though chemical precipitation plus biological treatment is both technologically available and economically achievable at all plants, none of EPA's preferred options identify this technology or chemical precipitation as BAT. All of the options except Options 4 and 5 identify impoundment as the BAT technology and propose to set BAT limits equal to current BPT limits.[575] Yet EPA has repeatedly made clear that "surface impoundments are not designed for, nor are they effective at, removing . . . dissolved metals" from combustion residual leachate.[576]

EPA's rationale for not selecting chemical precipitation as BAT for leachate violates the Clean Water Act. The Agency does not claim that chemical precipitation is not technologically available. Rather, the Agency chose not to propose chemical precipitation—technologically available and economically achievable for all plants greater than 50 MW—as BAT because "[t]he record demonstrates that the amount of pollutants collectively discharged in leachate by steam electric plants is a very small portion of the pollutants discharged collectively for all steam electric power plants (i.e., less than ½ a percent)."[577] EPA notes that "[b]ecause of the relatively low level of pollutants in this wastestream, and because EPA believes this is an area ripe for innovation and improved cost effectiveness, EPA is not putting forward [Option 4] as a preferred option."[578]

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[574] *Id.*
[575] 78 Fed. Reg. at 34,458.
[576] *See, e.g.*, TDD at 8-13; U.S. Envtl. Prot. Agency, Steam Electric Point Source Category: Final Detailed Study Report (EPA-821-R-09-008) xiii (Oct. 2009), *available at* http://water.epa.gov/scitech/wastetech/guide/steam-electric/upload/Steam-Electric_Detailed-Study-Report_2009.pdf.
[577] TDD at 8-32.
[578] TDD at 8-32-8-33.

EPA's justification for not setting BAT based on chemical precipitation is prohibited by the Clean Water Act. In sum, EPA's rationale is that investments in pollution control are not warranted because combustion residual leachate is a smaller source of pollution compared to FGD and coal ash transport wastewaters.[579] As a practical matter, EPA has underestimated loadings and impacts from this waste stream.[580] And combustion residual leachate has a significant adverse impact on public health and the environment even if loadings are less overall as compared to other coal-burning power plant discharges.[581]

Furthermore, the Clean Water Act prohibits BAT determinations based solely on these types of cost considerations. The inquiry is *not* whether the costs of a given control are warranted in EPA's estimation because Congress made the determination that investments in pollution control are warranted to the greatest extent practicable.[582] Rather, EPA must set BAT based on the Clean Water Act's overriding pollution elimination mandate, taking cost into account only when control expenses cannot be borne by the industry as a whole

EPA's record demonstrates that the costs of Options 4 and 5—both of which require chemical precipitation to reduce toxic discharges of leachate—can easily be borne by the industry as a whole.[583] Thus, impoundments are not BAT for leachate because they are not capable of reducing most toxic pollution in this wastestream and chemical precipitation plus biological treatment is both technologically available and economically achievable for the utility industry.

H. THE RULE SHOULD CLARIFY THAT DISCHARGES TO GROUNDWATER WITH A HYDROGEOLOGICAL CONNECTION TO SURFACE WATER WITHOUT A PERMIT IS PROHIBITED BY THE CLEAN WATER ACT.

EPA should clarify that discharges of leachate to groundwater with a hydrogeological connection to surface water without a permit are prohibited by the Clean Water Act. Discharges to groundwater with a direct hydrogeological connection to "waters of the U.S." fall within the scope of the Clean Water Act.[584] EPA itself has repeatedly acknowledged this in previous actions, although not yet by revising its NPDES regulations.[585] All unpermitted discharges from

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[579] *Id.*
[580] *See* discussion *supra*.
[581] *See* discussion *supra*.
[582] *See, e.g.*, *EPA v. Nat'l Crushed Stone Ass'n*, 449 U.S. 64, 71 (1980) ("In assessing BAT total cost is no longer to be considered in comparison to effluent reduction benefits.").
[583] *See infra* Section IX.
[584] *See, e.g.*, *Hernandez v. Esso Standard Oil Co.*, 599 F.Supp.2d 175, 181 (D. Puerto Rico 2009) (reviewing federal case law and holding "that the CWA extends federal jurisdiction over groundwater that is hydrologically connected to surface waters that are themselves waters of the United States").
[585] *See, e.g.*, U.S. Envtl. Prot. Agency, Office of Wastewater Mgmt., National Pollutant Discharge Elimination System Permitting of Wastewater Discharges from Flue Gas Desulfurization and Coal Combustion Residuals Impoundments at Steam Electric Power Plants, Attachment B at 2 (2010) ("Permitting authorities should examine the need for [NPDES permit requirements such as lined impoundments and seepage interception systems] for hydrologically connected discharges that cannot be regulated through traditional NPDES outfalls"); U.S. Envtl. Prot. Agency, Office of Wastewater Mgmt., EPA-833-K-10-001, NPDES Permit Writer's Manual (2010) ("If a discharge of pollutants to ground water reaches waters of the United States … it could be a discharge to the surface water (albeit indirectly via a direct hydrological connection, i.e. the ground water) that needs an NPDES permit"); U.S. Envtl. Prot. Agency, Notice of Final NPDES General Permit for Egg Production Operations in New Mexico and Oklahoma NMG800000 and OKG800000, 67 Fed. Reg. 47,362-63 (July 18, 2002) ("The permit prohibits the

a point source to these waters are violations of the CWA.[586] Leaks in a pollution containment system, like coal combustion waste landfills and ponds, are point sources.[587] Thus, discharges of toxic pollution from leaks in coal combustion waste landfills and ponds are prohibited without an NPDES permit.[588]

The majority of coal combustion waste landfills and surface impoundments are not properly lined. According to industry responses to the Steam Electric ELG Questionnaire, between sixty-one percent and ninety-nine percent of impoundments do not have protective composite liners.[589] Only about twenty-four percent of active landfills have protective composite liners.[590]

In light of the lack of basic safeguards at most of these disposal units, it is not surprising that many landfills and impoundments leak dangerous toxins into groundwater that flows into surface waters.[591] As EPA has acknowledged, "several damage case studies have documented impacts to surface waters due to ground water contamination from [coal combustion waste] impoundments and landfills."[592] For example, nearly half (30 of 67) of EPA's documented surface water damage cases from landfills and impoundments were caused by pollution from groundwater.[593] These dangerous discharges are illegal, and EPA should clarify that discharges from coal combustion waste landfills and impoundments to groundwaters that flow into surface waters are prohibited without a permit.

VII. BAT FOR FLUE GAS MERCURY CONTROL, GASIFICATION, AND NONCHEMICAL METAL CLEANING WASTEWATERS.

A. FLUE GAS MERCURY CONTROL WASTEWATER.

Under all of EPA's preferred options, flue gas mercury control (FGMC) waste would be handled dry, eliminating all discharges of FGMC wastewater. The record shows that dry handling of FGMC waste is the best available technology for handling this high-mercury waste stream.

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discharge of process wastewater pollutants from retention or control structures to groundwater that has a direct hydrologic connection to Waters of the United States").

[586] *Id.*

[587] 33 U.S.C. § 1362(14) (defining "point source" broadly and specifically including "container" in the definition); *See, e.g.*, *United States v. Earth Sciences, Inc.*, 599 F.2d 368 (10th Cir.) (noting that "[w]hen a [closed circulating system] fails because of flaws in the construction or inadequate size to handle the fluids utilized, with resulting discharge, whether from a fissure in the dirt bern or overflow of a wall, the escape of liquid from the confined system is a point source").

[588] In fact, discharges that result from leaks and other failures of a pollution containment system should never be authorized by an NPDES permit because BAT is to contain the pollution. *See* 33 U.S.C. §§ 1311(b)(1), 1311(b)(2)(A), and 1314(b) (mandating that permitting agencies set technology-based effluent limits for all discharges).

[589] *See infra* discussion re: CCR-Risk Assessment-Unlined Impoundments.

[590] *See infra* discussion re: CCR-Risk Assessment-Unlined Landfills.

[591] *See, e.g.*, EA at A-29-A-39.

[592] EA at 4-21.

[593] *See* EA at A-29-A-39.

FGMC wastewater is generated when a plant injecting activated carbon for mercury capture then handles the spent sorbent through a wet system.[594] Whether a plant injects the ACI upstream of downstream of the plant's primary particulate collection system, the vast majority of plants handle the spent sorbent through a dry system: 14 of 15 plants with downstream injection handle the waste dry, and 53 of 58 plants with upstream injection handle it dry.[595] Dry handling is thus not only BAT, but is actually standard industry practice. The record also shows that a number of plants with wet handling systems do not discharge the FGMC wastewater, and that these plants would be able to continue operating closed-loop wet systems.[596]

Dry handling of FGMC waste is also economically achievable—indeed, the record shows that it will have zero compliance costs due to the wide use of dry handling or closed-loop systems, and that the one plant currently discharging FGMC waste already has the capability to handle the material dry.[597] EPA's analysis shows that dry handling of FGMC wastewater is cost effective—dry handling of fly ash and FGMC is estimated to cost $27 per TWPE removed.[598] Finally, EPA concluded that there are no are no non-water quality environmental impacts associated with the proposed ELGs for nonchemical metal cleaning wastes.[599]

EPA acknowledges that not all plants will control mercury through activated carbon injection—some will add oxidizers to increase the capture rate of the mercury within a wet FGD system.[600] This practice increases the amount of mercury in the FGD wastewater, and therefore the toxicity of that wastewater both due to additional mercury and also more brominated compounds, since bromides are common coal treatment for mercury control purposes.[601] The report of Dr. Jeanne vanBriesen discusses these risks in more detail.[602] Although the record shows that the concentration of mercury in the wastewater will increase as a result of implementation of the MATS rule, EPA's cost-effectiveness estimates for biological treatment and evaporation are seriously underestimated, as they do not reflect the higher toxicity of FGD wastewater in the coming years.

B. GASIFICATION WASTEWATER.

Under all of the proposed options, vapor-compression evaporation is the technology basis for BAT for gasification wastewater. The record fully supports this BAT determination as the only two plants operating IGCC systems already employ evaporation.[603] The technology is essentially the same as that proposed for FGD wastewater except that no pretreatment or softening step is required.[604] There can be no dispute that the technology is therefore

[594] TDD at 7-41.
[595] *Id.* at 7-42.
[596] *Id.* at 8-26.
[597] *Id.* at 9-6.
[598] *Id.* at 8-34.
[599] EPA-HQ-OW-2009-0819-2133, at Table 1-1.
[600] TDD at 7-41.
[601] *Id.*
[602] VanBriesen Report, Appendix B, at 11-12.
[603] TDD at 7-42 to 7-43. EPA reports that a third plant, Edwardsport, plans to begin operating in 2012 and will operate an evaporation system.
[604] *Id.* at 7-43.

technologically and economically achievable. The record also shows that there are no non-water quality environmental impacts associated with the proposed ELGs for gasification wastewater.[605]

One of the pollutants of concern for gasification wastewater is cyanide, which is found in different forms, such as selenocyanate.[606] The Edwardsport IGCC is planning to use cyanide destruction in addition to evaporation, but because it had not yet begun commercial operation at the time EPA drafted the proposed rule, EPA asserts there are not sufficient data regarding cyanide removal to set limits "based on the performance of cyanide treatment as part of a BAT/BADCT (NSPS) regulatory option."[607]

The proposed technology for cyanide destruction is neither new nor untested. The Edwardsport plant will treat the distillate and condensate effluent with bleach and provide sufficient residence time for the bleach to react with the cyanide.[608] EPA has proposed several means of dealing with the lack of data, including transferring cyanide limits from another sector, or revisiting the standard after data are available from the Edwardsport facility.[609] The Edwardsport facility began operation in June 2013,[610] so effluent data sufficient for EPA to set a limit should be available prior to May 2014, when this rule will be finalized.

C. NONCHEMICAL METAL CLEANING WASTES.

Under all eight proposed options, EPA would base effluent limitations for nonchemical metal cleaning wastes on chemical precipitation, and establish limits for copper, iron, TSS, and oil & grease equal to the current BPT limits. However, if a facility current discharges nonchemical metal cleaning wastes without BAT limits for copper and iron, EPA would exempt those discharges from the nonchemical metal cleaning waste limits for iron and copper.[611]

1. EPA's proposed exemption for plants currently not complying with iron and copper BPT limits for nonchemical metal cleaning wastes.

The current ELGs define metal cleaning waste as "any wastewater resulting from cleaning [with or without chemical cleaning compounds] any metal process equipment, including but not limited to, boiler tube cleaning, boiler fireside cleaning, and air preheater cleaning."[612] In the 1982 ELGs, EPA established BPT limits for TSS, oil & grease, copper, and iron for all metal cleaning wastes.[613] EPA further established BAT limits for iron and copper for chemical metal cleaning waste, but reserved the development of BAT for nonchemical metal cleaning waste.[614]

[605] EPA-HQ-OW-2009-0819-2133, at Table 1-1.
[606] TDD at 7-43.
[607] 78 Fed. Reg. at 34,464.
[608] TDD at 7-43; 78 Fed. Reg. at 34,464.
[609] *Id.*
[610] *See* Duke Energy, Edwardsport Project Overview, at http://www.duke-energy.com/about-us/edwardsport-overview.asp (last viewed Sept. 15, 2013).
[611] 78 Fed. Reg. at 34,465.
[612] 40 C.F.R. § 423.11(d).
[613] 78 Fed. Reg. at 34,465.
[614] 40 C.F.R. § 423.13(f).

EPA has found that many permits authorize the discharge of nonchemical metal cleaning wastes based on the BPT requirements for low-volume wastes, and therefore, without limits on iron and copper. EPA states that because "the potential costs for discharges to comply with iron and copper limits is not known, EPA is proposing to provide an exemption from new copper and iron limitations or standards for existing discharges of nonchemical metal cleaning wastes from generating units that are currently authorized without copper and iron limits."[615] EPA would also exempt these wastes from any PSES standards.[616] In other words, EPA is proposing to legalize the illegal discharge practices that have been occurring around the country by rewarding those facilities who have skirted BPT limits on nonchemical metal cleaning wastes by discharging them as low volume wastes. Such an exemption is inappropriate and inconsistent with the Clean Water Act.

EPA justifies this exemption because some entities may have relied upon a 1974 guidance stating that metal cleaning wastes were low volume wastes. EPA rejected this guidance in the 1982 ELGs.[617] EPA conducted a survey of 45 permits, and found that 27% of plants currently discharge nonchemical metal cleaning waste with no limits on copper or iron, and another 9% has permits making it impossible to ascertain whether there were limits for these metals on this waste stream. *Id.*

Although we maintain that such an exemption is illegal and unjustified, EPA's proposed methodology of requiring entities to identify themselves as falling into the exemption is more appropriate than simply stating the criteria and make it available to any facility that later decides it falls within this category. As EPA notes, requiring facilities to identify themselves up front is the only way that EPA will obtain information about the scope of the exemption that it intends to create.

Furthermore, it is appropriate to require facilities to identify themselves during this comment period. No facility should lack notice of these major pending regulations, and the 90-day comment period affords a meaningful opportunity for affected facilities to identify any truly burdensome costs.

2. *EPA's proposal to set BAT equal to BPT established in 1982 Based on 1974 Data.*

Alternatively, EPA is proposing to establish BAT for nonchemical metal cleaning wastes equal to the BPT for all metal cleaning wastes, and to provide no exemption for existing discharges of nonchemical metal cleaning wastes in violation of the 1982 BPT standards for metal cleaning wastes.[618] Under this alternative, EPA would set PSES limits for copper. *Id.* Regarding this alternative, EPA seeks comment on the costs that facilities would incur to come into compliance with the existing BPT limits, where they have been avoiding those limits for the last 30 years.[619]

[615] 78 Fed. Reg. at 34,465.
[616] *Id.*
[617] *Id.* at 34,471.
[618] *Id.*
[619] *Id.*

We submit that such costs should not be considered as part of this rulemaking, and these are costs associated with compliance with existing standards, not new standards. EPA solicits information on the characteristics of nonchemical metal cleaning wastes, what actions would be needed for these wastes to comply with the copper and iron limits, and at what costs. The record shows that the only information EPA has regarding nonchemical metal cleaning wastes dates from 1974,[620] which is likely outdated for several reasons. First, methods of cleaning plant equipment may have progressed in the last 40 years. Second, the metals used in the plant process equipment may have changed. Finally, the types of coal burned or methods of treating the coal could have changed. All of these factors could change what pollutants are found in nonchemical metal cleaning waste, but EPA has not gathered the information to undertake this analysis.

As EPA has not yet gathered any of the information needed to make a proper BAT determination for these wastes,[621] it is not possible to fully evaluate EPA's proposal to set BAT for these wastes equal to BPT. However, setting BAT for copper and iron at levels equal to what was determined to be BPT in 1982 is highly questionable. Even BPT-limits set 30 years later should reflect advances in treatment technology. More importantly, because BAT is a more stringent standard that reflects the limits achievable by the best performing plant, and may not be based on cost-benefit analysis, it is extremely unlikely that a fully developed record would support setting BAT equal to 1982 BPT. Setting BAT equal to BPT is contrary to the technology-forcing nature of the BAT standard.

We support enforcing the current BPT limits for all metal cleaning wastes, and ask that EPA undertake a separate and comprehensive analysis of nonchemical metal cleaning wastes, under a separate rulemaking docket, so that the information gathering and analysis needed for a proper BAT determination does not unduly delay the critically needed standards for other waste streams.

VIII. BADCT FOR NEW SOURCES IS OPTION 5.

The Clean Water Act requires EPA to set and revise New Source Performance Standards (NSPS) for new sources that "reflect[] the greatest degree of effluent reduction achievable through application of the best available demonstrated control technology, processes, operating methods, or other alternatives, including, where practicable, a standard permitting no discharge of pollutants" or BADCT.[622] BADCT is the most stringent standard for control of discharges. As EPA notes, "Congress envisioned that new sources could meet tighter controls than existing sources because of the opportunity to incorporate the most efficient processes and treatment systems into the facility design."[623] In this case, EPA expressly noted that all of the treatment technologies identified in Option 5 are technologically available, and the record supports this determination.[624] EPA improperly rejected Option 5 for NSPS solely because of higher costs associated with evaporation systems for FGD wastewater.[625]

[620] TDD at 6-33 to 6-34.
[621] *See* 78 Fed. Reg. at 34,472.
[622] 33 U.S.C. § 1316(a)(1).
[623] TDD at 8-37.
[624] TDD at 8-40.
[625] *Id.*

EPA is required to "take into consideration the cost of achieving such effluent reduction, and any non-water quality environmental impact and energy requirements."[626] As courts have recognized, the language related to consideration of costs in section 306 is "virtually identical" to the language in in section 304(b)(2)(B) for existing sources.[627] Similar to the relevant cost inquiry for BAT determinations,

> [t]here is no language in s[section] 306 requiring a cost-benefit analysis. Rather, the EPA is required only to take costs under "consideration." We conclude, therefore, that a cost-benefit analysis is not required in determining the reasonableness of the cost of achieving the new source standards. What is required for new source standards is a thorough study of initial and annual costs and an affirmative conclusion that these costs can be reasonably borne by the industry.[628]

Thus, the relevant inquiry for EPA when setting NSPS is whether the "costs can be reasonably borne by the industry" as a whole,[629] and costs are "to be given even less weight under section 306 than for existing sources."[630]

EPA states that it assessed the economic impacts of NSPS requirements on new units in two different ways: (1) using the Integrated Planning Model (IPM) to determine "whether the costs of complying with the proposed ELGs would affect future capacity additions" and (2) "by comparing the incremental costs for new units to the overall cost of *building and operating* new units, on a per MW basis"[631] Yet the rule and Regulatory Impact Analysis only provide the analysis for these two metrics for Option 4.

With respect to the first metric, EPA states that it didn't even run the IPM for Option 5 "[d]ue to scheduling constraints" and because screening-level analysis for existing plants showed that Option 5 costs might result in "financial stress" to some utilities.[632] As discussed in greater detail elsewhere, EPA's screening-level analysis does not support EPA's dismissal of Options 4 and 5 for existing plants.[633] EPA states that this "analysis, while helpful to understand potential cost impact, does not generally indicate whether profitability is jeopardized, cash flow is affected, or risk of financial distress is increased."[634] Furthermore, even incorrectly assuming that all compliance costs will be borne by utilities without at least some part passed on to consumers in the form of higher utility rates,[635] the results of the "screening-level analysis shows

[626] 33 U.S.C. § 1316(b)(1)(B).
[627] *See, e.g., Am. Iron & Steel Inst. v. EPA*, 526 F.2d 1027, 1059 (3d Cir. 1975).
[628] *CPC Int'l, Inc. v. Train*, 540 F.2d 1329, 1341-42 (8th Cir. 1976) (internal citations omitted). *See also Am. Iron & Steel Inst.*, 526 F.2d at 1059.
[629] *CPC Int'l, Inc.*, 540 F.2d at 1341-42 (internal citations omitted).
[630] *Am. Iron & Steel Inst.*, 526 F.2d at 1059.
[631] RIA at 3-11.
[632] *Id.* at 5-6 to 5-7.
[633] *See infra* Section IX; *see also* attached Synapse Report, Appendix A.
[634] RIA at 4-2.
[635] RIA at 4-2.

that the entity-level compliance costs are low in comparison to the entity-level revenues; very few entities are likely to face economic impacts at any level."[636] The results of the plant-level cost-to-revenue analysis also show that "for the majority of steam electric plants, including those expected to incur zero compliance costs, costs would not exceed the 1 percent of revenue threshold under any of the eight regulatory options."[637] In addition, the compliance costs used in the screening-level analysis don't account for "anticipated unit retirements and conversions announced between August 2012 and April 2013, and announced retirements, repowerings, and conversions that are scheduled to occur by 2022", all of which would reduce total annualized compliance costs.[638] Thus, there is no basis at all for EPA declining to run the IPM for Option 5, especially where it would preclude a more thorough examination of the economic impacts to new sources associated with Option 5.

With respect to the second metric, EPA evaluates only the relative magnitude of compliance costs for new units for Option 4. Furthermore, much of the detailed costing information for NSPS is unavailable to the public as three out of four NSPS costing memoranda in the docket are not available due to CBI claims.[639] The attachment to the one non-CBI memorandum is also identified as CBI.[640] For Option 4, EPA concludes that compliance costs for a new unit at a new plant are 1.5% of expected annualized costs; compliance costs for a new unit at an existing plant are 1.2% of expected annualized costs.[641] Using information in the TDD, Commenters were able to calculate incremental costs as a percent of new generation.

Table 6 – Comparison of Option 4 and Option 5 Incremental Costs and as Percent of New Generation[642]

			Option 4 from RIA		Option 5 from TDD	
Cost Component	Costs of New Coal-fired Generation ($2010/MW)a	Unit Configuration	Incremental Compliance Costs ($2010/MW)	% of New Generation Cost (RIA)	Incremental Compliance Costs ($2010/MW)	% of New Generation Cost (TDD)
Capital	$ 2,981,947.00	New Plant	$ 21,773.00	0.7%	$47,307.69	1.6%
		Existing Plant	$ 19,911.00	0.7%	$43,307.69	1.5%
Annual O&M	$ 66,427.00	New Plant	$ 3,093.00	4.7%	$ 9,000.00	13.5%
		Existing Plant	$ 2,281.00	3.4%	$ 6,561.54	9.9%
Total annualized costs	$ 329,487.00	New Plant	$ 5,013.00	1.5%	$13,173.37	4.0%
		Existing Plant	$ 4,037.00	1.2%	$10,382.04	3.2%

636 RIA at 4-13.
637 RIA at 4-3.
638 RIA at 4-5, 4-12.
639 *See* EPA, CBI Memorandum to the Steam Electric Rulemaking Record: New Source Performance Standards (NSPS) Costing Memorandum, Docket No. EPA-HQ-OW-2009-0819-2210; EPA, CBI Characteristics of New Generating Units and NSPS Analyses, Docket No. EPA-HQ-OW-2009-0819-1966; EPA, CBI NSPS Capital and O&M Compliance Costs, Docket No. EPA-HQ-OW-2009-0819-197581.
640 *See* Memorandum from TJ Finseth, ERG, to Steam Electric Rulemaking Record Re Steam Electric NSPS Costs Methodology (DCN SE02130) (Apr. 19, 2013).
641 RIA at 3-12.
642 *See* RIA at 3-12 tbl. 3-5 *and* TDD at 9-46 tbl. 9-12. Calculations are from Synapse Economics.

With respect to total annualized costs, Option 5 will only result in a 4% increase in the total annualized costs of a new 1,300 MW coal-fired generation unit at a new plant, and a 3.2% increase in total costs for an existing plant. EPA states that a 1.5% increase under Option 4 is not too high, but EPA does not identify the threshold above which the increase in annualized costs as a share of baseline costs cannot be reasonably borne by the industry. There is no basis in the record for EPA's rejection of Option 5 as BADCT based on the increase in total annualized costs in relation to total costs for the new unit.[643] Thus, EPA's record does not demonstrate that the costs of Option 5 cannot be reasonably borne by industry, and Option 5 is BADCT for new sources.

IX. THE COST OF OPTIONS 4 AND 5 CAN BE REASONABLY BORNE BY THE INDUSTRY.

The rulemaking record makes clear that compliance costs for Options 4 and 5 can be reasonably borne by the industry, notwithstanding EPA's failure to select either option as preferred. EPA did not propose Option 4 as a preferred option "because of concerns expressed above associated with the projected compliance costs associated with zero discharge requirements for bottom ash for unit equal to or below 400 MW."[644] EPA rejected Option 5 on different grounds. EPA eliminated Option 5 from consideration at a very early stage of the rulemaking, based on screening-level analyses, and thus never conducted the full set of economic analyses for Option 5. "EPA did not select Option 5 as its preferred option for BAT because of the high total industry cost for the option ($2.3 billion/year annualized social cost) and because of preliminary indications that Option 5 may not be economically achievable."[645] Additionally, "certain screening-level economic impact analyses indicated that compliance costs may result in financial stress to some entities owning steam electric plants."[646]

In rejecting Options 4 and 5 based on cost, EPA applied the wrong legal standard. The proper standard, noted by several courts of appeal, is whether the compliance costs can be reasonably borne by the industry as a whole.[647] EPA itself acknowledges that the agency "has traditionally looked at affordability of the rule to the regulated industry."[648] When the correct legal standard

[643] EPA may have overestimated the capital costs for a new 1,300 MW coal plant. For example, EPA estimates costs of approximately $2,982/kW, but a Black & Veatch calculator last updated in 2011 estimates costs for this type of unit between $3,000/kW to $4,000/kW. Ryan Pletka PE, Black & Veatch's (RETI'S) Cost of Generation Calculator (May 16, 2011), *available at* http://www.energy.ca.gov/2011_energypolicy/documents/2011-05-16_workshop/presentations/Ryan_Pletka_B&V.pdf.

[644] 78 Fed. Reg. at 34,473. EPA rejected Option 4 for the additional reason that, in EPA's view, Option 4's proposal to treat leachate with chemical precipitation is not warranted at this time. "Because of the relatively low level of pollutants in this way stream, and because EPA believes this is an area ripe for innovation and improved cost effectiveness, EPA is not putting forward this option as a preferred option." *Id.*

[645] *Id.*; *see also id.* at 34,477 (rejecting Option 5 as a preferred option for NSPS "because of its high costs, which are substantially higher than the costs for Option 4 and the other options evaluated for NSPS.").

[646] *Id.* at 34,473.

[647] *See* Legal Framework, *supra* Section II.

[648] 78 Fed. Reg. at 34,473; *see also* 74 Fed. Reg. 62,996, 63,023 (Dec. 1, 2009) ("EPA has determined that this cost, which represents less than one tenth of one percent of the current total value of annual construction activity, can be

is applied, EPA's own analysis establishes that the cost of both Options 4 and 5 can be reasonably borne by the industry.

Moreover, EPA's decisions not to choose Options 4 and 5 appear to be influenced by cost-benefit analysis. The statute and the decisions of several courts of appeal make clear that BAT limitations cannot be based on cost-benefit analysis. Congress precluded EPA from relying on cost-benefit analysis to develop BAT limitations because of concerns that the data on benefits will not be as extensive or robust as the data on costs, and therefore cost-benefit comparisons will inevitably skewed toward prioritizing costs. This rulemaking bears out Congress's concerns, since EPA's cost-benefit analysis systematically overestimates costs and underestimates benefits.

A. THE RECORD DEMONSTRATES THAT THE COST OF OPTIONS 4 AND 5 CAN BE REASONABLY BORNE BY THE INDUSTRY.

EPA has considered costs in this rulemaking using the wrong legal standard.[649] The Clean Water Act requires EPA, in determining BAT, to evaluate whether the cost of controls can be reasonably borne by the industry as a whole,[650] not whether "compliance costs may result in financial stress to some entities owning steam electric plants," as EPA did here in its "screening-level" analysis of the proposed regulatory options.[651] If the statute left any doubt, courts long ago established that BAT limitations must be based on the cost to the industry as a whole, not the cost to individual plants, and certainly not based on the cost to the most inefficient, marginal plants.[652] For even the less stringent BPT limitations, the "courts of appeal have consistently held that Congress intended Section 304(b) to . . . preclude the EPA from giving the cost of compliance primary importance," and this applies with greater force to the more stringent BAT limitations.[653] EPA has failed to heed this language from the courts and instead proposes to reject Options 4 and 5 on the grounds that they are too costly. The record does not support EPA's proposed decision here, which falls short of the stringent requirements of BAT.

Using a 3% discount rate, the total social costs of Options 4 and 5 are $1.38 billion and $2.32 billion per year, respectively.[654] Using a 7% discount rate, the total social costs are $1.32 billion and $2.2 billion annually for Options 4 and 5.[655] EPA never discloses the annual revenues of the plants subject to this rule, and we were unable to make the calculation ourselves because of revenue information redacted as CBI from the responses to the survey questionnaire. Nonetheless, as context for the total annual compliance costs, it is worth noting that 2011 revenues for retail sales of electricity were $371 billion.[656]

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reasonably borne by the industry."); 73 Fed. Reg. 70,418, 70,463 (Nov. 20, 2008) (with respect to BCT, "[a] technology is economically achievable if its costs may be " reasonably borne" by the CAFOs.").

[649] *See* Legal Framework, *supra* Section II.

[650] *Waterkeeper Alliance*, 399 F.3d at 516; *Rybachek*, 904 F.2d at 1290-91.

[651] 78 Fed. Reg. at 34,473.

[652] *See, e.g., Am. Iron & Steel Inst.*, 526 F.2d at 1051; *see also supra* Section II.

[653] *Chem. Mfrs. Ass'n*, 870 F.2d at 204 (citing cases).

[654] 78 Fed. Reg. at 34,493.

[655] *Id.*

[656] EIA, Table 2.3, Revenue from Retail Sales of Electricity to Ultimate Customers, *available at* http://www.eia.gov/electricity/annual/html/epa_02_03.html.

The costs of both options can be reasonably borne by the industry as a whole based on the cost-to-revenue ratios EPA estimated. Under Option 5, nearly three quarters of the entire industry will have no compliance costs, and an additional 8% of plants will have costs that are less than 1% of revenues.[657] Under Option 5, 82% of plants have costs less than 1% of revenues, and EPA claims that "[e]ntities incurring costs save below 1% of revenues are unlikely to face economic impacts."[658] According to EPA's own data and benchmarks, 82% of the industry is "unlikely to face economic impacts" from Option 5, which directly contradicts EPA's assertion that Option 5 has a "high total industry cost" and "may not be economically achievable."[659] Indeed, EPA states in the RIA that its entity-level cost-to-revenue analysis indicates that for all options, "the entity-level compliance costs are low in comparison to the entity-level revenues; very few entities are likely to face economic impacts at any level."[660]

Moreover, by EPA's own admission, the "screening level" cost-to-revenue analysis overstates the economic impacts of Options 4 and 5. EPA's cost-to-revenue ratios are biased toward overestimating costs, because EPA made the "counterfactual, conservative assumption of zero cost pass-through" of compliance costs from utilities to ratepayers.[661] In other words, EPA assumed that utility companies themselves would bear 100% of the compliance costs of the rule, despite the fact that utilities in a majority of states are regulated by public utility commissions pursuant to state laws that authorize utilities to incorporate environmental compliance costs into their rates.[662] EPA conducted only one sensitivity analysis to correct this obvious bias by assuming that 50% of costs would be passed on to customers through higher rates. Unfortunately, EPA conducted the sensitivity for Option 4 but not for Option 5, because EPA eliminated Option 5 from further consideration after screening-level analyses—that is, the cost to revenue ratio analysis erroneously assuming that the company bears 100% of the compliance costs. Nonetheless, EPA's sensitivity analysis for Option 4 shows that an assumption of zero pass-through costs significantly biases the results of EPA's cost-to-revenue analysis by showing a greater economic impact than is likely to occur, as the following table demonstrates.

[657] 78 Fed. Reg. at 34,494.
[658] *Id.* at 34,495.
[659] *Id.* at 34,473.
[660] RIA at 4-9. EPA's parent-company level analysis showed that of 507 parent companies, only 20 would have costs between 1% and 3% of revenues and only 15 would have costs greater than 3% of revenues. *Id.* 442 parent companies would have compliance costs less than 1% of revenues. *Id.*
[661] *Id.* at 34,494.
[662] RIA at 2-18 to 2-19; *see also* M.J. Bradley & Associates LLC, Public Utility Commission Study (Mar. 31, 2011) (prepared for EPA's mercury and air toxics rule), *available at* http://www.epa.gov/airtoxics/utility/puc_study_march2011.pdf. Moreover, in many traditionally regulated states, the costs of environmental compliance are added to rate base and companies are not only reimbursed for their compliance costs but earn a rate of return on capital investments.

Table 7

Cost-pass-through assumption	Total plants Subject to Option 4	No information on revenues	0% cost-to-revenue ratio	0-1% cost-to-revenue ratio	1-3% cost-to-revenue ratio	>3% cost-to-revenue ratio
Company bears 100% of cost[663]	1079	5	798	111	117	48
Company bears 50% of cost[664]	1079	5	798	199	67	10

Under a 50-50% split between the company and customers, Option 4 would cause 92% of plants to incur compliance costs less than 1% of revenues, which EPA claims is a level at which a plant "is unlikely to face economic impacts." As a result, the evidence in the record does not support EPA's rejection of Option 4 because of compliance costs.[665]

Just as the 50-50 sensitivity analysis showed that the economic impacts from Option 4 would be far lower than EPA initially estimated, the sensitivity analysis would likely show that the economic impacts from Option 5 would be dramatically lower than EPA calculated. In particular, the number of plants and parent companies incurring compliance costs less than 1% of revenues would be far greater in a scenario where companies can pass on some of the compliance costs to customers. This undermines EPA's rationale for rejecting Option 5, since the sensitivity analysis shows that changing EPA's counterfactual, conservative assumption that companies will bear 100% of the compliance costs changes the results significantly.

Moreover, EPA has presented no basis for the cost-to-revenue thresholds it has selected. EPA has presented no analysis of the electric power industry to indicate that 1% or 3% of revenues is a meaningful number for the industry. Nor has EPA substantiated its assertions that costs greater than 1%, or greater than 3%, the revenues indicates economic stress. EPA has set the bar for economic stress much higher in other rulemakings, claiming that costs equal to 5% of revenue are a "moderate" impact.[666] Nonetheless, even under these unsubstantiated thresholds, the cost-to-revenue ratios for Options 4 and 5 are comparable to the cost-to-revenue ratios of other final effluent guidelines.[667]

[663] All figures in this role come from 78 Fed. Reg. at 34,494.
[664] All figures in this row come from RIA at B-2.
[665] *See* 78 Fed. Reg. at 34,473.
[666] *See* 69 Fed. Reg. 51,892, 51,916 (Aug. 23, 2004) ("facilities show additional moderate impacts if they are not projected to close but incur compliance costs in excess of 5 percent of facility revenue").
[667] 50 Fed. Reg. 45,212, 45,233 (Oct. 30, 1985) (compliance costs less than 1% of revenues for most firms in the metal molding and casting industry); 69 Fed. Reg. 51,892, 51,917-18 (Aug. 23, 2004) (5.8% of commercial facilities in the concentrated aquatic animal production industry would have costs greater than 3% of revenues under the final rule).

EPA modeling of early plant retirements caused by the rule demonstrates that the costs of Options 4 and 5 can be reasonably borne by the industry as a whole. EPA unjustifiably eliminated Option 5 at an early stage and thus did not model the impact of Option 5 on plant retirements. According to EPA's modeling of Option 4, however, that option would cause a net decrease of only .1% of total industry capacity, equivalent to 317 MW.[668] This represents nine units expected to close early as a result of Option 4, *id.* at 34,472, out of over 2000 units in the industry.[669] The percentage of plants expected to close early as a result of Option 4 are far lower than the projected closures for many other final effluent limitations guidelines.[670] Courts have consistently upheld final effluent limitations guidelines that EPA projected would cause some plants to shut down.[671] Having approved final rules determining that the Clean Water Act's stringent BAT mandate required effluent limitations to be set at a level that would cause a far greater percentage of the affected industry to retire early, EPA has no basis for rejecting Option 4 or 5 on the grounds that they would lead to excessive plant closures.

Even judged by cost-effectiveness,[672] which is not the appropriate test,[673] both Options 4 and 5 can be reasonably borne by the industry. Options 4 and 5 would cost $70 and $111 per TWPE.[674] The cost-effectiveness of Option 4 is below the cost of four other final effluent limitations guidelines, and close to the cost of two additional final guidelines.[675] The cost-effectiveness of Option 5 is lower than the cost of two final effluent limitations guidelines, and is roughly 4 times less expensive than the most expensive guidelines EPA has promulgated.[676]

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[668] 78 Fed. Reg. at 34,498.

[669] *Id.* at 34,447.

[670] 65 Fed. Reg. 81,242 (Dec. 22, 2000) (11.7% of centralized waste treatment plants expected to close); 52 Fed. Reg. 42,522 (Nov. 5, 1987) (4% of chemicals manufacturing facilities expected to close); 48 Fed. Reg. 49,126 (Oct. 24, 1983) (3.8% of aluminum forming plants expected to close); 69 Fed. Reg. 51,892 (Aug. 23, 2004) (2.9% of concentrated aquatic animal production plants expected to close); 47 Fed. Reg. 52,848 (Nov. 23, 1982) (2.5% of leather tanning plants expected to close); 63 Fed. Reg. 18,504 (Apr. 15, 1998) (2.3% of pulp and paper mills expected to close).

[671] *See, e.g.*, *Am. Paper Inst. v. Train*, 543 F.2d 328 (D.C. Cir. 1976) (upholding BPT guidelines that EPA projected would cause 7-10 out of 188 paper mills to shut down); *Ass'n of Pac. Fisheries*, 615 F.2d at 808-09 (upholding BPT limits that EPA estimated would cause 33% of non-remote Alaskan salmon canning facilities to close and would cause 57% of non-remote Alaskan fresh and frozen salmon facilities to close); *Weyerhaeuser*, 590 F.2d at 1047 (rejecting challenges to effluent guidelines that EPA estimated would cause 8 plants to close); *Chem. Mfrs. Ass'n,* 870 F.2d at 250-51 (upholding as reasonable effluent guidelines that EPA stated might cause 14% of indirect dischargers to close).

[672] In the attached report, Appendix E, Dr. Phyllis Fox notes that the cost-effectiveness for bottom ash conversions is inflated because EPA has overestimated the cost of converting to zero discharge systems. *See* Fox Report, Appendix E, at 17. For example, EPA has calculated cost-effectiveness at the unit level and ignored the cost savings from retrofitting multiple units at the same plant or multiple plants in the same fleet, thereby driving up the cost-effectiveness numbers. *Id.*

[673] Cost-effectiveness measures cost as a function of pollutant removals at the plant level, whereas the proper legal test is whether the industry as a whole can reasonably bear the costs of a control technology. At least one circuit has held that EPA is not required to conduct a cost-effectiveness analysis for BAT guidelines. Responding to the argument that "EPA is under a duty to make a reasonable determination with regard to cost effectiveness," the Fifth Circuit held that "EPA is not required to show a direct cost/benefit correlation, but only that a beneficial substitution is 'technologically and economically achievable.'" *API v. EPA*, 858 F.2d 261, 264 n.4 (5th Cir. 1988).

[674] *See* 78 Fed. Reg. at 34,504.

[675] RIA at D-7 to D-8 ($84, $96, $121, and $404 per TWPE for the metal molding and casting, pharmaceutical manufacturing B/D, aluminum forming, and electrical and electrical components industries, respectively, and $65 and $69 per TWPE for waste combustors and nonferrous metals forming and metal powders industries).

[676] *Id.* ($121 and $404 per TWPE for the aluminum forming and electrical and electronic components industries).

Even under this test – which is not the appropriate standard for EPA to use when determining BAT – both Options 4 and 5 pass, and are reasonable.

Every form of cost analysis that EPA has conducted indicates that the costs of both Options 4 and 5 can be reasonably borne by the industry as a whole. Whether the agency considers total costs relative to total industry revenues, the cost-to-revenue ratio at the plant or parent-company level, plant closures, or even the unlawful cost-effectiveness metric, the costs of Options 4 and 5 can be reasonably borne by the electric power industry. Accordingly, both Options 4 and 5 are economically achievable and there is no support in the record for rejecting them on economic grounds.

B. THE CLEAN WATER ACT PROHIBITS EPA FROM BASING BAT LIMITATIONS ON COST-BENEFIT ANALYSIS.

The Clean Water Act precludes EPA from basing BAT limitations on a cost-benefit analysis. This rulemaking record demonstrates the compelling reasons that motivated Congress to remove cost-benefit analysis from the factors considered in determining BAT. As Congress foresaw more than 40 years ago, cost-benefit analysis skews toward prioritizing costs because benefits are far more difficult to quantify and monetize. EPA's cost-benefit analysis overestimates costs and dramatically underestimates benefits. This skewed analysis makes for poor policy decisions and, in any event, cannot be used under the Clean Water Act to determine BAT limitations.

1. The statute prohibits EPA from basing BAT limitations on cost-benefit analysis.

As explained above, the Clean Water Act precludes EPA from basing BAT limitations on consideration of costs versus benefits.[677] "[I]n assessing BAT, total cost is no longer to be considered in comparison to effluent reduction benefits."[678] As the D.C. Circuit has explained, Congress affirmatively rejected amendments which would have required cost-benefit balancing for BAT.[679] Seven circuit courts of appeal have affirmed, in accord with the Supreme Court's decisive pronouncement in *National Crushed Stone*, that EPA cannot base BAT guidelines on cost-benefit analysis. The Supreme Court's recent discussion of cost analysis under a separate Clean Water Act provision, 33 U.S.C. § 1326, reinforces this long-settled law.[680]

Congress forbad cost-benefit analysis when developing the BAT standards for sound policy reasons. The sponsors of the 1972 Clean Water Act amendments recognized that the costs of pollution controls are more easily quantified than the benefits, and therefore any cost-benefit analysis would be biased toward emphasizing costs over benefits.[681] Additionally, Congress believed that a technology-forcing mandate that did not weigh costs against benefits would spur the development of cheaper control technologies over the long run.[682] These policy concerns are

[677] *See supra* Section II.
[678] *EPA v. Nat'l Crushed Stone*, 449 U.S. 64, 71 (1980); *see also Am. Iron & Steel*, 526 F.2d 1027, 1051-52 (3rd Cir. 1975) ("With respect to the [BAT] standards," Congress intended "that there should be no cost-benefit analysis.").
[679] *See Weyerhaeuser v. Costle*, 590 F.2d 1011, 1046 (D.C. Cir. 1978).
[680] *See Entergy Corp. v. Riverkeeper, Inc.*, 556 U.S. 208 (2009) (only certain specific Clean Water Act standards "authorize cost-benefit analysis," and the BAT analysis does not fall within this group).
[681] S. Rep. No. 92-414, at 47 (1971).
[682] *Id.* at 50-51.

illustrated by EPA's analysis, which overstates the cost of compliance and dramatically underestimates the benefits.[683] EPA's analysis shows why all too often a cost-benefit analysis winds up comparing better defined, and usually overestimated costs against poorly studied, and significantly underestimated the benefits.[684] Anticipating this dilemma, Congress wisely removed cost-benefit analysis from the factors to be considered when establishing BAT limitations.[685]

2. *EPA overestimated costs.*

As explained more fully in the accompanying report by Synapse Energy Economics, compliance cost estimates prepared before the installation of controls often overestimate costs.[686] Studies have documented this effect in major federal rule makings.[687] Researchers have identified explanations for the trend. Once a rule is finalized and the deadline approaches, a market is created, or strengthened, in the pollution controls required, which often leads to technological innovation and a drop in price.[688] Additionally, cost analyses may rely on high-end estimates because of conservative, counterfactual assumptions by agencies and because of strategic behavior by the regulated industry.[689] Finally, since the regulated industry has better access to information on compliance costs, industry is better positioned to point out underestimates than the public is able to point out overestimates of costs.[690]

In this case, it is not necessary to wait until the compliance deadline to compare EPA's cost estimates to the actual compliance costs. Instead, the attached report by Dr. Phyllis Fox, Appendix E, documents that EPA's assumptions have resulted in significantly overestimating the cost of compliance.[691] In the report, Dr. Fox explained that EPA overestimated the cost of converting to zero discharge systems for handling bottom ash in five ways. Specifically, EPA (1) ignored economies of scale when installing controls at multiple units at the same plant or multiple plants in the same fleet; (2) calculated compliance costs for units that are likely to convert to zero discharge systems for handling bottom ash or to retire for reasons unrelated to this rule; (3) overestimated operating and maintenance costs; (4) omitted increased sales of bottom ash from zero discharge systems; and (5) used an inappropriately high annualization factor and an inappropriately short assumed equipment lifetime.[692]

Dr. Fox focused her comments on EPA's inflated cost estimates for bottom ash handling systems, but the errors she identified applied to the controls for other waste streams as well. EPA ignored economies of scale when calculating the cost of controls for all waste streams, which

[683] Synapse Report, Appendix A, at 14-35.
[684] *Id.* at 16-17.
[685] *Id.* at 14-15.
[686] Synapse Report, Appendix A.
[687] *Id.* at 16-18.
[688] *Id.* at 16.
[689] *Id.* at 16-17.
[690] *Id.* at 17.
[691] Fox Report, Appendix E.
[692] *Id.* at 22-39. Moreover, while EPA's cost analyses focused on pre-tax compliance costs, EPA acknowledges elsewhere that after-tax costs are a more accurate measure of the economic impact of the rule. As a result, EPA's focus on pre-tax compliance costs overestimates the economic impacts of the rule. This bias affects the cost analyses for all waste streams for all proposed options.

systematically inflates the cost of all proposed options. Similarly, EPA's inclusion of units that have already announced they will retire results in overestimating the total compliance cost for all proposed options. As explained in the attached, 88 units have announced that they are shutting down completely or switching fuels, and will not incur compliance costs – yet these units are included in EPA's calculation of total compliance costs.[693] Finally, the inappropriately high annualization factor was used to calculate the cost of all options, and therefore increased the cost of all options. Taken together, these assumptions and methodologies have dramatically inflated EPA's cost estimates for all options, confirming research showing that *ex ante* compliance costs are usually overestimated.

3. EPA underestimated benefits.

On one side EPA has placed well-defined, but overestimated, costs, while on the other side of the ledger has placed benefits that the agency itself acknowledges are incomplete and underestimated. Yet EPA presents tables of costs and benefits as if the two sets of data are equally well-defined and can be meaningfully compared.[694] Nothing could be farther from the truth, as EPA's own costs and benefits document explains, and as additional materials suggest.

EPA did not monetize whole categories of benefits. Some of these benefits were not discussed at all; some were discussed qualitatively but not quantified or monetized; others were quantified but not monetized. But for all of the following categories, EPA did not assign a monetary value to include in the benefits calculations.

Table 8 – Benefits not Monetized by EPA[695]

Benefit	Discussed in BCA?	Monetized?
Reduction in other adverse health effects from reduced exposure to pollutants via fish consumption	Yes	No
Improved fisheries yield and harvest quality due to improvement of aquatic habitat for commercial fisheries	Yes	No
Increase in tourism revenue from increased water recreation	Yes	No
Increased property values from water quality improvements	Yes	No
Reduced impingement and entrainment of fish from reduced water withdrawals	Yes	No
Reduced sediment deposition of toxic pollutants	Yes	No
Reduced adverse health effects from improved drinking water quality	Yes	No
Reduced treatment costs for drinking water and irrigation water	Yes	No
Reduced adverse health effects from lower exposure to pollutants during water recreation	Yes	No

[693] List of Announced Retirements Included in EPA's Cost Calculations, submitted by Commenters as an exhibit to this letter.
[694] *E.g.*, 78 Fed. Reg. at 34,526.
[695] Synapse Report, Appendix A, at 22. Benefits containing a * indicate that EPA did not discuss the category in the Benefits and Costs document but did discuss the benefits qualitatively in other documents in the record.

Reduced bromide pollution in drinking water	No*	No
Reduction in surface impoundments being an attractive nuisance to wildlife	No*	No
Increased sales of coal combustion residuals	No*	No
Reduced air emissions from reducing the parasitic load from impoundments	No*	No
Reduced air emissions from completely dry handling of ash	No*	No
Value of land available for redevelopment when impoundments are closed	No*	No
Avoided costs of BPJ determinations	No	No
Avoided costs in TMDLs	No	No

The benefits not monetized by EPA are discussed in the attached Synapse Report. Additionally, the attached analysis from NRDC explains that EPA did not account for the significant benefits from Options 4 and 5 of reduced surface water withdrawals.[696] EPA calculated that power plants would reduce water use by 153 billion gallons per year, or about 419 million gallons per day, under Options 4 and 5, due to reductions in water use for handling ash transport and for the recycling of FGD wastewater.[697] Although power plant withdrawals of cooling water are substantially greater than this amount, the amount of process water that can be saved by the proposed rule's two most stringent options is about as much water as is used by all the homes in North Carolina,[698] and thus a significant amount of water to save with any single regulatory measure. The water savings resulting from the rule will be especially helpful for those states facing deepening water-scarcity challenges caused by climate change. Yet EPA did not describe any of these benefits of the rule, let alone attempt to quantify or monetize them.
Significant water withdrawals such as those from power plants have many adverse impacts, including lowering groundwater recharge or natural stream flow levels (thus impacting instream flow[699]), and affecting fish, wildlife, or other living resources and their habitat.[700] Any measure that reduces surface water withdrawals, thereby restoring natural flows, provides both environmental and economic benefits.[701] Reduced withdrawals will either restore instream flows in areas with low flow conditions, or increase natural stream flows, both of which improve aquatic ecosystems and enhance recreational opportunities, such as by increasing fish stocks.[702]

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[696] NRDC, Associated Water Savings and Benefits to Reduced Surface Water Withdrawals.
[697] TDD at 12-13 – 12-14; Becky Hayat & Ed Osann, Natural Resources Defense Council, "Steam Electric Effluent Guidelines: Associated Water Savings and Benefits to Reduced Surface Water Withdrawals" (Sept. 20, 2013) [hereinafter "NRDC Memo"]. Option 4a would reduce water use by 103 billion gallons per year. TDD at 12-14. Options 3, 3a, and 3b would reduce water use by 52.7 billion, 49.9 billion, and 52.1 billion gallons per year, respectively. *Id.* Options 1 and 2 would only reduce water use by 2.82 billion gallons per year each. *Id.*
[698] NRDC Memo at 1 (citing Kenny, J.F., Barber, N.L., Hutson, S.S., Linsey, K.S., Lovelace, J.K., and Maupin, M.A., 2009, Estimated use of water in the United States in 2005: U.S. Geological Survey Circular 1344).
[699] Instream flow refers to the state in which water remains in its natural course as opposed to water that has been diverted artificially for other purposes.
[700] NRDC Memo at 1 (citing U.S. Geological Survey, Simulation of the Effects of Water Withdrawals, Wastewater Return Flows, and Land-Use Change on Streamflow in the Blackstone River Basin, Massachusetts and Rhode Island (2007); Susquehanna River Basin Commission, Low Flow Protection Policy Related to Withdrawal Approvals (Dec. 14, 2012)).
[701] *Id.* at 9-11.
[702] *Id.* at 10.

In addition, reducing surface water withdrawals may directly improve water quality, such as by increasing dilution of pollutants or decreasing temperature.[703] This increased water quality has the added benefit of increasing agricultural productivity and property values.[704]

For each category of benefits mentioned above, EPA set the value equal to zero.[705] In other words, EPA notes that there is a category of benefits from the rule, but in the face of uncertainty surrounding the monetary value of those benefits, treats the value as zero. This systematically biases the cost-benefit analysis toward prioritizing costs. There are other ways to deal with uncertainty besides setting the value of the uncertain variable to zero. For example, EPA could develop ranges for each of the categories of benefits. Alternatively, EPA could apply different multipliers to the total monetized benefits to arrive at a series of low, mid, and high cases to account for uncertainty surrounding the un-monetized benefits. Regardless of how exactly EPA deals with the un-monetized benefits, one thing is clear: their value is not zero. Treating these categories of benefits as if they have no monetary value is inconsistent with EPA's own claim that these are actual benefits from the rule.[706]

In addition to benefits that were not monetized at all, there are many categories of benefits for which EPA likely underestimated the monetary value. The following table, from the Synapse report, lists the benefits that, with one exception, were underestimated.[707]

[703] *Id.* at 10-11.
[704] *Id.* at 11.
[705] *Id.* at 19-35.
[706] *Id.* at 19-20.
[707] *Id.* at 26.

Table 9 – Benefits Monetized but Underestimated by EPA

Benefit	Inclusion	Quantification	Monetization
Reduced incidence of cancer from reduced exposure to arsenic from fish consumption	Included	Quantified (Low)	Monetized (Low)
Reduced IQ losses to infants from reduced in-utero mercury exposure from maternal fish consumption	Included	Quantified (Low)	Monetized (Low)
Reduced IQ losses to children ages 0 to 7 from reduced childhood exposure to lead from fish consumption	Included	Quantified (Low)	Monetized (Low)
Reduced need for specialized education from reduced childhood exposure to lead from fish consumption	Included	Quantified (Low)	Monetized (Low)
Reduced mortality from exposure to NOx, SO_2 and particulate matter (PM2.5)	Included	Quantified (Low)	Monetized (Low)
Improved aquatic and wildlife habitat from improved ambient water quality in receiving reaches	Included	Quantified (Low)	Monetized (Low)
Enhanced swimming, fishing, boating, and near-water activities from improved water quality	Included	Quantified (Low)	Monetized (Low)
Increased aesthetics from improved water clarity, color, odor, including nearby site amenities (residing, working, traveling)	Included	Quantified (Low)	Monetized (Low)
Enhanced existence, option, and bequest values from improved ecosystem health.	Included	Quantified (Low)	Monetized (Low)
Reduced risks to aquatic life from exposure to steam electric pollutants	Included	Quantified (Low)	Monetized (Low)
Improved T&E habitat and thus potential increase in T&E population	Included	Quantified (Low)	Monetized (Low)
Reduced air emissions of CO_2 resulting in avoided climate change /global warming impacts	Included	Quantified (Low)	Monetized (Low)
Increased availability of groundwater resources from reduced groundwater withdrawals	Included	Quantified (Low)	Monetization (Uncertain)
Reduced groundwater contamination	Included	Quantified (Low)	Monetized (High)
Reduced risk of impoundment failures due to changes in the use of impoundments	Included	Quantified (Low)	Monetization (Uncertain)

This rulemaking illustrates the pitfalls of cost-benefit analysis that Congress sought to avoid by ensuring that BAT limitations are not based on a cost-benefit analysis. As Congress understood more than 40 years ago, data sources for compliance costs are far more complete and robust than the data for environmental benefits. And EPA has compounded the problem by using conservative, counterfactual assumptions that drive up the costs and economic impacts, such as by assuming that 100% of compliance costs will be borne by utilities and 0% will be passed on to consumers. Ultimately, EPA's cost-benefit analysis compares well-defined but nonetheless overestimated compliance costs with incomplete and underestimated benefits. For reasons of coherent and logical policy, this cost-benefit analysis should not drive the rule. And for legal reasons, the cost-benefit analysis cannot be a factor in deciding the BAT limitations.

X. BEST MANAGEMENT PRACTICES (BMPS) FOR CONSTRUCTION, OPERATION AND MAINTENANCE OF CCR SURFACE IMPOUNDMENTS MUST ESTABLISH TIMELY AND ENFORCEABLE MINIMUM STANDARDS.

A. THE CWA AUTHORIZES BMPS TO CONTROL RELEASES OF TOXIC OR HAZARDOUS POLLUTANTS FROM CCR SURFACE IMPOUNDMENTS.

EPA is considering establishing BMPs that would apply to CCR surface impoundments that receive, store, dispose of, or are otherwise used to manage coal combustion residuals including

FGD wastes, fly ash, bottom ash (which includes boiler slag), leachate, and other residuals associated with the combustion of coal to prevent uncontrolled discharges from these impoundments.[708]

We find that the Clean Water Act authorizes EPA to establish specific and enforceable BMPs to ensure both dam stability and safe closure of surface impoundments that discharge, may discharge or are hydrologically connected to surface water.[709] For new sources, CWA Section 306 authorizes the promulgation of performance standards.[710] For existing coal combustion residual (CCR) surface impoundments, CWA section 304(e) authorizes BMPs supplemental to any effluent limitations to control toxic or hazardous pollutants in runoff, spillage or leaks, and sludge or waste disposal that the Administrator determines are associated with or ancillary to the industrial process and may contribute significant amounts of pollutants to the nation's waters.[711] Furthermore, CWA section 304(e) requires controls established under this subsection to be included "as a requirement … in any permit issued to a point source pursuant to section 1342 of this title."[712] CWA section 402(a)(2) authorizes the imposition of conditions in NPDES permits, which include BMPs and monitoring requirements, necessary to ensure compliance with all other applicable requirements.[713] Lastly, CWA's implementing regulations allow the permitting authority to modify existing permits during the existing permit terms.[714]

EPA's NPDES permit regulations reflect the EPA's longstanding interpretation of the CWA to authorize BMPs that address toxic or hazardous pollutant discharges from waste units similar to CCR surface impoundments. 40 C.F.R. §122.44(k), entitled "Establishing limitations, standards, and other permit conditions (applicable to State NPDES programs ...)," provides that permits may include BMPs to control or abate the discharge of pollutants when: (1) "[a]uthorized under section 304(e) of the CWA for the control of toxic pollutants and hazardous substances from ancillary industrial activities"; (2) "[a]uthorized under section 402(p) of the CWA for the control of storm water discharges"; (3) "[n]umeric effluent limitations are infeasible"; or (4) "[t]he practices are reasonably necessary to achieve effluent limitations and standards or to carry out the purposes and intent of the CWA."[715] EPA has employed BMPs to address releases at concentrated animal feeding operations[716] and for storm water discharges.[717] To adequately address the pollutant discharges from CCR surface impoundments, BMPs must include the specific requirements discussed below, and these conditions must be imposed in NPDES permits that are timely modified.

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[708] 78 Fed. Reg. at 34,458.
[709] For a discussion on EPA's authority to regulate units hydrologically connected to surface water, *see* Section VI.H. of these comments, *supra*.
[710] *See* 33 U.S.C. § 1316.
[711] *See id.* § 1314(e).
[712] *Id.*
[713] 33 U.S.C. § 1342(a)(2).
[714] *See* 40 C.F.R. § 122.62.
[715] 40 C.F.R. § 122.44(k). *See also Citizens Coal Council v. U.S. E.P.A.*, 447 F.3d 879, 896 (6th Cir. 2006).
[716] See 40 C.F.R. § 122.23.
[717] *See id.* §§ 122.30-37.

B. THE BMPS FOR CCR SURFACE IMPOUNDMENTS MUST INCORPORATE ALL THE REQUIREMENTS SET FORTH IN THE REGULATIONS PROMULGATED FOR COAL SLURRY IMPOUNDMENTS BY THE MINE SAFETY AND HEALTH ADMINISTRATION (MSHA) AT 30 C.F.R. § 77.216.

In EPA's 2010 proposed CCR rule, EPA proposed incorporation of the MSHA standards for coal slurry impoundments set forth in 30 C.F.R. § 77.216.[718] After finding these design and inspection requirements necessary to protect human health and the environment from actual and potential releases occurring at CCR surface impoundments, EPA incorporated all MSHA requirements governing reporting,[719] design plans and design standards,[720] and inspection and corrective action requirements[721] applicable to coal slurry impoundments. In the preamble to the ELG rule, EPA similarly found that "MSHA's regulations are comprehensive and directly applicable to the dams used in surface impoundments at coal-burning utilities to manage CCRs."[722] Accordingly, BMPs for CCR surface impoundments must incorporate, at minimum, all of the requirements set forth in the proposed CCR rule at 40 C.F.R. §§ 1302-4. Certain additional requirements, described below, must also be included.

C. EPA MUST INCLUDE ADDITIONAL REQUIREMENTS IN THE BMPS FOR CCR SURFACE IMPOUNDMENTS.

The MSHA regulations are a useful template for impoundment BMP requirements, but they must be strengthened by requiring: (1) daily or weekly inspections by trained personnel; (2) specific elements to be included in each inspection; (3) reporting and corrective action requirements for specific structural integrity warning signs like increases in seepage; and (4) annual engineering inspections and reports with no exceptions.

First, although the MSHA regulations establish a baseline inspection frequency of once per week, they allow for less frequent inspections at the discretion of the Director, where justified by an operator.[723] This clause is open-ended and could be used to justify monthly or even annual inspections. The contents of an inspection are also left open-ended. By contrast, recent NPDES permits for the Tennessee Valley Authority (TVA) coal plants in Tennessee require daily inspections with specific elements. The NPDES permit for the Gallatin Fossil Plant, for example, states that

> Daily inspections shall, at a minimum, include observations of dams, dikes and toe areas for obvious changes in erosion, cracks or bulges, subsidence, seepage, wet or soft soil, changes in geometry, the depth and elevation of the impounded water, sediment or slurry, freeboard, changes in vegetation such as overly lush,

[718] *See* U.S. EPA, Hazardous and Solid Waste Management System; Identification and Listing of Special Wastes; Disposal of Coal Combustion Residuals From Electric Utilities, 75 Fed. Reg. 35,128 (June 21, 2010), 35,259-61.
[719] *See* 40 C.F.R. § 1302.
[720] *See id.* § 1303.
[721] *See id.* § 1304.
[722] *See* 78 Fed. Reg. at 34,667.
[723] *See* 30 C.F.R. § 77.216-3(a).

> obstructive vegetation and trees, outlet controls, drains and any other changes which may indicate a potential compromise to impoundment integrity.[724]

The permit also requires that these inspections be carried out by personnel with dam safety training.[725]

Secondly, the MSHA regulations begin with an annual engineering inspection requirement, but then allow it to be reduced to a five-year interval when an operator certifies that there have been no changes.[726] Annual inspections, however, should be a required baseline. In fact, the Gallatin NPDES permit requires such annual engineering inspections,[727] The BMPs should require engineering inspections on an annual basis for the lifetime of the impoundment.

Finally, although the MSHA regulations require reporting of "potentially hazardous condition[s],"[728] the BMP should specify the form and scope of the required report, a time period in which it must be made, the appropriate personnel who must receive this report, and required follow-up. The Gallatin NPDES permit requires that

> Within 24 hours of discovering a change in the impoundment that indicates a potential compromise to the structural integrity of the dike (e.g., significant changes in seeps, boils, bulges, or cracks), the permittee must make contact with division personnel describing the findings of the inspection, corrective measures taken or proposed (if known), and expected outcomes. TVA must keep current a list of division personnel complete with after-hours contact information and must speak directly to someone on this list within the 24 hour period. Failure to notify the division within 24 hours will be a violation of this permit. In addition, the permittee must submit a follow-up report within 5 days summarizing the incident, corrective actions taken and outcomes. Additional reports pertaining to the event may be required by the Director.[729]

In order to prevent coal ash impoundment failures, EPA must build on the MSHA example to include: (1) daily or weekly inspections by trained personnel; (2) specific elements to be included in each inspection; (3) reporting and corrective action requirements for specific structural integrity warning signs like increases in seepage; and (4) annual engineering inspections and reports with no exceptions.

D. EPA MUST REQUIRE SPECIFIC BMPS IN NPDES PERMITS TO PROVIDE FOR PUBLIC PARTICIPATION IN THE SUBSTANCE OF THE CONDITIONS, ENSURE ENFORCEABILITY, AND GUARANTEE PROTECTION OF HUMAN HEALTH AND THE ENVIRONMENT.

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[724] Tennessee Department of Environmental Conservation (TDEC), NPDES permit No. TN0005428 for the Gallatin Fossil Plant, Part II, Section B (2012).
[725] *Id.*
[726] *See* 30 C.F.R. § 77.216-4.
[727] *Id.*
[728] 30 C.F.R. § 77.216-3(b).
[729] TDEC, NPDES permit No. TN0005428 for the Gallatin Fossil Plant, Part II, Section B (2012).

If EPA fails to require specific BMPs in NPDES permits, with clear reporting and corrective action requirements, then the states will continue to write NPDES permits without enforceable structural integrity standards. Specific standards for design, inspection and corrective action are set forth in both the MSHA regulations and in the CCR proposed rules modeled after those regulations. The BMPs should require adherence to these specific standards, and these standards should be incorporated into NPDES permits to ensure consistent and effective controls on all coal ash impoundments nationwide.

The current (administratively extended) permits for three TVA plants in Alabama and Kentucky serve as useful examples of the failure of the status quo; all of these permits effectively ignore structural integrity and lack conditions that would ensure against significant releases of toxic pollutants to surface waters. The two Alabama permits include identical—and wholly ineffective—language purporting to address structural integrity under the heading "Best Management Practices (BMP) Plan Requirements."[730] The language is deficient in at least three general ways. First, there is no indication that this language is intended to require BMPs for structural integrity; it appears to be boilerplate meant to address small, miscellaneous waste streams. Second, since the permits only require BMP plans to be completed after the permits become effective, there is no opportunity for public participation. Third, because the specific requirements of the BMP plans are not themselves conditions of the permit, these requirements are difficult to enforce. Most glaringly, the permits require BMP <u>plans</u>, but not BMPs. And although the Alabama Department of Environmental Management (ADEM) reserves the right to review and correct the BMP plans, it does not require TVA to submit the plans to ADEM, instead requiring that the BMP plans be reviewed <u>by the permittee</u> within six months of the permit effective date. The two Kentucky permits for TVA plants use different boilerplate language, but otherwise suffer from the same deficiencies outlined above for the Alabama permits.[731]

NPDES permits like these, devoid of clear requirements for BMP implementation, reporting, and corrective action, clearly provide no safeguards to prevent structural failures and associated releases of pollutants to waters of the United States. EPA must fill this regulatory gap with clear prescriptions for permit language adequate to detect and respond to early warnings of compromised dike stability.

E. EPA MUST ENSURE THAT BMPS FOR CCR SURFACE IMPOUNDMENTS ARE IMPLEMENTED AS SOON AS POSSIBLE TO PREVENT RELEASES OF TOXIC OR HAZARDOUS POLLUTANTS TO SURFACE WATER.

If EPA establishes BMPs for design and operation of CCR surface impoundments, EPA must ensure a means of timely implementation. In light of the substantial risk of failure and the deadly consequences that may ensue, the requirements to inspect, maintain and safely operate the nation's 309 high and significant-hazard impoundments cannot be postponed.

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[730] Alabama Department of Environmental Management (ADEM), NPDES permit No. AL0003867 for the Colbert Fossil Plant, Part IV.B (2005); ADEM, NPDES permit No. AL0003875 for the Widows Creek Fossil Plant, Part IV.B (2005).

[731] Kentucky Department for the Environment (KDEP), KPDES permit No. KY0004201 for the Paradise Fossil Plant (2004); KDEP, KPDES permit No. KY0004219 for the Shawnee Fossil Plant (2005).

EPA can and must require compliance with the BMPs as soon as possible, but no later than three years from the effective date of the final rule.[732] EPA clearly acknowledges the imminent need for such requirements. In the preamble, EPA stated

> the BMP requirements being considered by the Agency in this rulemaking and in the CCR rulemaking are critical to ensure that the owners and operators of surface impoundments become aware of any problems that may arise with the structural stability of the surface impoundment before they occur and, thus, prevent catastrophic releases, such as those that occurred at Martins Creek, Pennsylvania and TVA's Kingston, Tennessee facility.[733]

In fact, EPA points out that the MSHA requirements were created as a result of the 1972 catastrophic slurry pond failure at Buffalo Creek, West Virginia that killed 125 people and destroyed or damaged nearly 1,000 homes.[734] Yet the capacity for unregulated CCR impoundments to cause as much or greater harm than the Buffalo Creek disaster is a genuine threat that EPA must minimize as soon as possible. In fact, the amount of toxic material released from the Kingston dam in 2008 was *10 times* the volume released at Buffalo Creek.

Furthermore, new information concerning the risk of releases due to impoundment conditions is now available for more than 500 CCR impoundments.[735] Such information, particularly for the 309 high and significant hazard dams, provides new and critical information concerning the potential for significant releases to surface water and supports compliance with the BMPs as expeditiously as possible. This information is discussed in more detail below.

1. Imminent threats at high and significant CCR surface impoundments were revealed in the EPA's dam assessment reports.

As described in detail in comments submitted by Earthjustice and others in response to EPA's Notice of Data Availability,[736] EPA's assessments of CCR dams documented a substantial number of structural integrity problems at the dams, including insufficient factors of safety,[737] absence of geotechnical engineering analyses to determine structural stability, inadequate inspection procedures, seeps, sloughing, and the absence of emergency action plans.[738] Furthermore, we pointed out that the more in-depth geotechnical analyses conducted by TVA of their own dams following the Kingston dam disaster revealed even greater problems with

[732] 33 U.S.C. § 1311(b)(2)(C), -(D). *See also* discussion *infra* section XI.
[733] 78 Fed. Reg. at 34,466.
[734] *See id.* at 34,467.
[735] *See* EPA impoundment assessment reports, *available at* http://www.epa.gov/osw/nonhaz/industrial/special/fossil/surveys2/index.htm.
[736] Comments of Earthjustice et al. to U.S. EPA, Office of Resource Conservation and Recovery, Notice of Data Availability and Request for Comment (Coal Ash NODA), 78 Fed. Reg. 46,940 (Aug. 2, 2013) (comments filed Sept. 3, 2013) (Document ID No. EPA-HQ-RCRA-2012-0028-0111).
[737] *See, for example*, Duke Energy, W.C. Beckjord Station, New Richmond, Ohio: Significant-hazard ash Pond C determined to be "marginally stable;" and Indianapolis Power & Light Company, Eagle Valley Generating Station, Martinsville, Indiana: High and significant-hazard Ponds D and E, respectively, had factors of safety less than 1.0, and both dams experienced failures in 2007 and 2008.
[738] *See* http://www.epa.gov/osw/nonhaz/industrial/special/fossil/surveys2/index.htm.

structural stability, resulting in 12 or the 24 dams undergoing needed repairs and a substantial change in the inspection and maintenance procedures carried out by TVA.[739] It is likely that if additional dams were subject to a complete geotechnical analysis, additional deficiencies relating to the structural integrity of the dams would have been uncovered. This is because, for a great many of the dams, the analyses necessary to determine structural stability simply had not been done.[740] The engineers who examined the high and significant coal ash impoundments often recommended further stability analyses of the structures because there was little information on the materials and construction methods used on most of the dams.[741]

2. *The uncertain current status of the high and significant hazard dams found in poor condition by EPA argues for immediate action to establish enforceable requirements for safe design and adequate inspections.*

As a result of EPA-contracted assessments of coal ash impoundments by dam safety experts from 2009 to 2013, EPA found 144 coal ash impoundments in poor condition (28 percent of the total number of dams inspected).[742] The majority of coal ash impoundments found by EPA to be in poor condition have a high or significant hazard rating (80 of 144 impoundments).[743] In fact, EPA found one out of five high hazard dams in poor condition (20 percent).[744] Of 239 significant hazard dams, EPA found 28 percent in poor condition.

These comments focus on the actions taken by EPA and dam owners to resolve the problems discovered at the nation's most dangerous coal ash dams. In total, EPA found 16 high hazard impoundments in poor condition. These dams have the highest likelihood of causing severe damage if they fail. Such dams are rated "high" hazard because their failure is likely to cause loss of life. Because no federal regulations have ever held these dams to basic design and construction standards, existing coal ash dams must be closely watched. Professional engineers designed only three of the dams.[745] Their average age is 45 years-- five years over the estimated 40-year lifespan of a coal ash surface impoundment.[746]

The high hazard impoundments rated in poor condition received this rating because they were found to have structural stability below federal dam standards, lacked critical technical documentation pertaining to structural integrity, and because of observed physical problems.

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[739] *See* Comments of Earthjustice et al. to U.S. EPA, Office of Resource Conservation and Recovery, Notice of Data Availability and Request for Comment (Coal Ash NODA), 78 Fed. Reg. 46,940 (Aug. 2, 2013) (comments filed Sept. 3, 2013) (Document ID No. EPA-HQ-RCRA-2012-0028-0111).
[740] *See* http://www.epa.gov/osw/nonhaz/industrial/special/fossil/surveys2/index.htm.
[741] *Id. See also* comments of Jack Spadaro, submitted by Commenters as an exhibit to this letter.
[742] *See* U.S. Envt'l Prot. Agency, Coal Combustion Residuals Impoundment Assessment Reports: Summary Table for Impoundment Reports, (July 19, 2013), *available at* http://www.epa.gov/osw/nonhaz/industrial/special/fossil/surveys2/.
[743] *See* U.S. Envt'l Prot. Agency, Coal Combustion Residuals Impoundment Assessment Reports*: Summary Table for Impoundment Reports,* (July 19, 2013), *available at* http://www.epa.gov/osw/nonhaz/industrial/special/fossil/surveys2/.
[744] *Id.*
[745] *See* EPA, Information Response from Electric Utilities, http://www.epa.gov/osw/nonhaz/industrial/special/fossil/surveys/index.htm.
[746] Age data was available for 15 of the 16 high hazard dams at http://www.epa.gov/osw/nonhaz/industrial/special/fossil/surveys/index.htm.

The observed problems most often involved erosion or the threat of future erosion due to uncontrolled vegetation, animal burrows, seepage, and sloughing. Additional problems included inadequate inspection programs, lack of emergency action plans, and failure to perform hydraulic and stability analyses. The Table entitled "Problems Identified by EPA at Sites with High-Hazard, Poor-Rated Dam(s)" summarizes the problems found at the 16 dams.[747]

The large number of coal ash surface impoundments found by EPA in "poor" condition should have precipitated a very rigorous effort on the part of EPA to ensure that serious problems were remediated as soon as possible. The record shows, however, that nothing of the kind occurred. In the absence of enforceable federal requirements or permit conditions, EPA took only informal action to urge dam owners to take remedial steps. Instead of notices of violation, EPA wrote owners letters describing the deficiencies. Instead of enforceable administrative consent orders, the dam owners responded to EPA's findings solely with letters estimating dates when critical problems would be addressed.[748] Often these industry letters, however, registered disagreement with EPA's findings or provided only vague assurances that work would be completed by a certain date.[749]

After the passage of several years, only half of the plant owners of the 16 dams have submitted to EPA *any* documentation pertaining to the problems identified at their dams.[750] This is not surprising because EPA did not require owners to submit documentation of completion of remedial activities.[751] For the four owners who did submit documents, EPA has no records indicating that they reviewed the materials for sufficiency, even though the documents address issues central to structural stability. Lastly, EPA has never re-inspected any of the dams to determine whether all problems have been resolved. Essentially, there is no evidence that EPA has done anything to re-assess dam conditions at these high hazard dams after the initial inspection. The only follow-up with dam owners occurred in mid-August 2013. At that time EPA sent a set of form letters to owners of dams inspected by EPA, informing them that is the company's responsibility to ensure that their dams are structurally sound.[752] The letters were completely silent regarding the sufficiency of repairs or the need for any further action on the part of the company to resolve the deficiencies that were identified by EPA's dam safety experts. EPA did not ask the companies for documentation of any voluntary actions completed, despite the fact that in many cases the Agency had no such confirmation.[753]

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[747] Submitted by Commenters as an exhibit to this letter.

[748] *See* Company Response/Action plans, *available at* http://www.epa.gov/osw/nonhaz/industrial/sSpecial/fossil/surveys2/.

[749] *See, e.g*, Company Response/Action Plan for Progress Energy Carolinas, Cape Fear Power Station, *available at* http://www.epa.gov/osw/nonhaz/industrial/special/fossil/surveys2/pec_capefear_response.pdf.

[750] *See* EPA Table, "List of Action Plan Follow Up Reports/Materials," received in response to Earthjustice Freedom of Information Act Request, dated April 2013, submitted to EPA from Lisa Evans, Attorney, Earthjustice, submitted by Commenters as an exhibit to this letter.

[751] Of 516 impoundments inspected, EPA, to date, has received information for approximately 127 impoundments, about one-fourth of all dams inspected. *Id.* The response rate remains low even for structural deficiencies identified at high and significant hazard dams. For those 80 high and significant hazard dams that received "poor" condition ratings, only 24 companies submitted any follow-up documentation to EPA.

[752] *See, e.g.*, Barnes Johnson, Letter to Fred Holt, Progress Energy Carolinas, Aug. 13, 2013, *available at* http://www.epa.gov/osw/nonhaz/industrial/special/fossil/surveys2/finlet/pec_finlet.pdf.

[753] *Id.*

Lastly, there has been no citizen involvement, because in the absence of federal regulations and permit conditions, those threatened by these dams have no legal role to play in ensuring the safety of their communities. The establishment of specific and enforceable BMPs is thus needed to facilitate effective oversight and enforcement, guarantee transparency and public participation, and ensure compliance with critical safety standards.

3. *The absence of emergency action plans for CCR impoundments demonstrates the need to establish enforceable requirements for safe operating practices as soon as possible.*

Emergency action plans (EAPs) exist to prevent or minimize any potential loss of life and damage to property from dam failures, and having an EAP in place is fundamental to effective emergency action planning. Without an EAP, dam personnel may not be able to identify a potential emergency condition and respond accordingly. In addition, dam personnel may not be able to properly notify downstream authorities, appropriate first-responders or communities about an emergency.

Of the 61 plants found by EPA to be maintaining high or significant-hazard dams in poor condition, only 38 plants were examined for the presence of an EAP. Of these 38 plants with dams rated as in poor condition, less than 40 percent had emergency action plans. Over 60 percent of these high and significant hazard dams, where serious deficiencies were found, had no EAPs whatsoever. In any other context, federal government officials would find this situation extremely alarming.

In fact, a recent report by the Office of the Inspector General (OIG) of the U.S. Department of the Interior (DOI), entitled "Bureau of Land Management, National Park Service, and Office of Surface Mining Reclamation and Enforcement's Safety of Dams: Emergency Preparedness," evaluated this very issue.[754] In this December 2012 report, the OIG examined the emergency preparedness of three government agencies within the DOI that operate high hazard dams. Together, the Bureau of Land Management's (BLM), National Park Service's (NPS) and Office of Surface Mining Reclamation and Enforcement's (OSM) manage 584 dams that are classified as either high or significant hazard. The OIG measured the agencies' emergency preparedness against the DOI requirement that a bureau's dam safety program include an EAP for all of its high and significant hazard dams.[755]

The OIG's findings included recommendations for immediate management changes. The OIG found that each of the three agencies failed to have all required EAPs in place and that not every EAP had been properly prepared, exercised, reviewed, and updated to ensure an effective response to incidents. According to a U.S. Bureau of Reclamation official, an average of four dam incidents occur annually[756] at these dams. The OIG concluded that because these dam

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[754] Office of the Inspector General of the U.S. Department of the Interior, Bureau of Land Management, National Park Service, and Office of Surface Mining Reclamation and Enforcement's Safety of Dams: Emergency Preparedness (Report No. WR-EV -MOA-0015-2011).
[755] *Id.* at 1.
[756] The DOI annual average number of four dam incidents is for the years 1995 through 2009. This annual average number is probably higher because there is no required uniform method of reporting dam incidents within DOI. As such, DOI does not have a comprehensive list of dam incidents.

incidents put the public and property at risk, it is important for BLM, NPS, and OSM to have EAPs in place. The OIG provided detailed recommendations for each Agency to ensure that adequate EAPs were timely completed.[757] In contrast, EPA failed to quantify the industry-wide absence of effective EAPs or to take action to ensure that missing EAPs at high and significant hazard CCR impoundments were completed in a timely and satisfactory manner.

F. IF EPA DOES NOT REQUIRE TIMELY IMPLEMENTATION OF BMPS FOR DESIGN AND INSPECTION OF CCR IMPOUNDMENTS, EPA MUST REQUIRE COMPLIANCE WITH REQUIREMENTS UNDER RCRA.

The inclusion of dam safety requirements in BMPs is an urgent matter, as described above. If EPA is unable or unwilling to require compliance with the BMPs no later than three years from the effective date of the final rule, EPA should proceed with establishing identical requirements under RCRA authority.

G. EPA MUST ESTABLISH BMPS FOR ALL CCR SURFACE IMPOUNDMENTS WHERE RELEASES WOULD DISCHARGE TO SURFACE WATER AND WHERE GROUNDWATER IS HYDROLOGICALLY CONNECTED TO SURFACE WATER.

EPA has proposed to establish BMPs only for those CCR surface impoundments that are "direct dischargers."[758] This is clearly unacceptable because such a narrow exercise of EPA's authority under the CWA leaves much of the universe of large and life-threatening CCR impoundments unaddressed. According to question D3-3 of the ELG questionnaire, only 457 of the 1504 impoundments that industry self-reported are direct dischargers.[759] Furthermore, only 104 of the 309 high and significant hazard CCR impoundments admit to being in this category.[760] A list of those CCR impoundments is attached as Exhibit X. The graph below illustrates the distribution and demonstrates that if EPA restricts the BMPs to direct dischargers, the majority of impoundments will escape these essential safety requirements.[761]

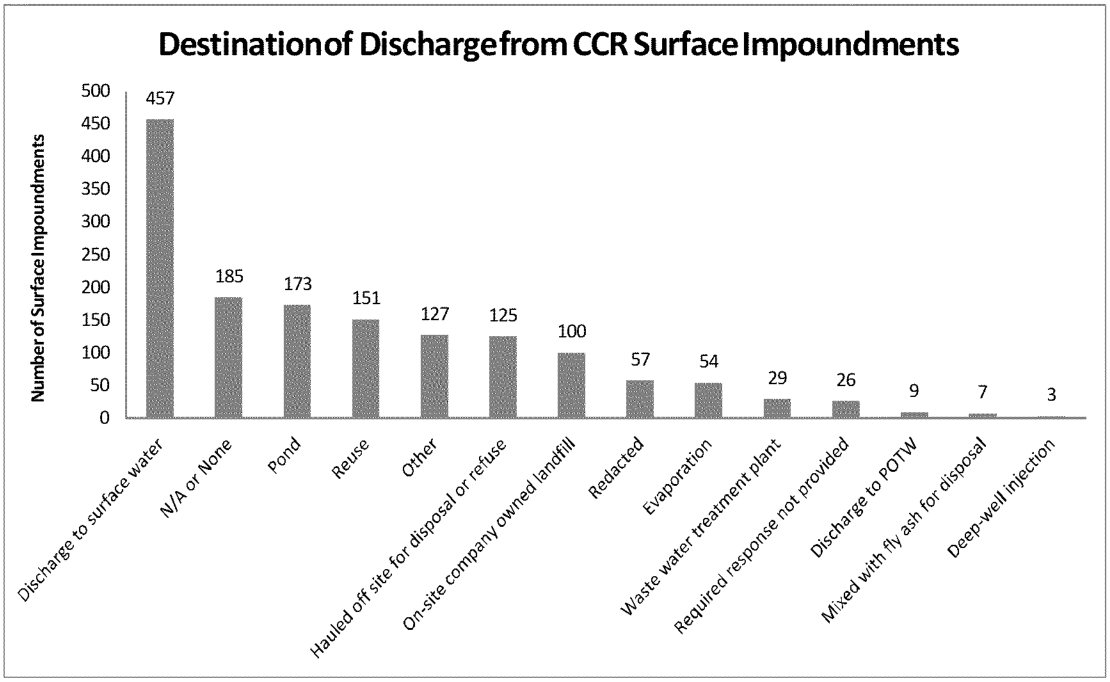
[757] Office of the Inspector General of the U.S. Department of the Interior, Bureau of Land Management, National Park Service, and Office of Surface Mining Reclamation and Enforcement's Safety of Dams: Emergency Preparedness (Report No. WR-EV -MOA-0015-2011).

[758] 78 Fed. Reg. 34,466.

[759] *See* Responses to Steam Electric Questionnaire, Part D, Pond/Impoundment Systems, Question D3-3.

[760] *Id.*

[761] *See* Responses to Steam Electric Questionnaire, Part D, Pond/Impoundment Systems, Question D3-3.



EPA must apply the BMPs to all CCR surface impoundments under the jurisdiction of the Clean Water Act. First, EPA must apply BMPs to all CCR impoundments that, in the event of a breach or failure, would discharge pollutants to surface water. The fact that such impoundments may not currently be discharging directly to surface waters is irrelevant to the purpose of the BMPs. If the releases that the BMPs are intended to prevent would result in the discharge of pollutants to surface water, these impoundments must be permitted and the conditions of their permits must include the BMPs. Second, EPA must also include CCR impoundments that discharge leachate to groundwater with a hydrological connection to surface water. The CWA prohibits such discharges without a permit.[762] Leaks in a pollution containment system, like CCR impoundments, are point sources that require a NPDES permit.[763] Consequently, NPDES permits for these CCR impoundments must contain the proposed BMPs.

H. APPLICATION OF BMPS TO CCR SURFACE IMPOUNDMENTS MUST BE NO LESS STRINGENT THAN THE APPLICABILITY REQUIREMENTS FOR COAL SLURRY IMPOUNDMENTS UNDER MSHA.

If EPA establishes BMPs for dam safety, the applicability requirements concerning size, height and volume of waste material impounded must be no less stringent than the requirements applicable to coal slurry impoundments under MSHA regulations at 33 C.F.R. § 77.216.

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[762] *See* Section IX.H, supra.

[763] 33 U.S.C. § 1362(14) (defining "point source" broadly and specifically including "container" in the definition); *See, e.g.*, *United States v. Earth Sciences, Inc.*, 599 F.2d 368 (10th Cir.) (noting that "[w]hen a [closed circulating system] fails because of flaws in the construction or inadequate size to handle the fluids utilized, with resulting discharge, whether from a fissure in the dirt berm or overflow of a wall, the escape of liquid from the confined system is a point source").

XI. EPA SHOULD ESTABLISH SPECIFIC AND ENFORCEABLE BMPS FOR CLOSURE OF CCR SURFACE IMPOUNDMENTS.

The billions of tons of waste currently disposed in CCR surface impoundments have the potential to significantly harm both surface water and groundwater with hydrogeological connections to surface water. Consequently it is essential that EPA establish BMPs to ensure CCR impoundments are safely closed to minimize pollutant discharge to such waters. According to industry responses to EPA's Office of Solid Waste Information Request in 2009, the storage capacity for 637 coal ash surface impoundments is approximately 283 billion gallons of coal ash waste.[764] This total underestimates the total amount of storage capacity because it does not include over 400 CCR impoundments, later identified by industry in the 2010 ELG IC.[765] These reservoirs of toxic pollutants, both active and inactive, pose grave threats to water quality of surface water and groundwater. The failure to include BMPs for surface impoundment closure in a final ELG rule would be arbitrary and capricious and without rational basis in law.

In fact, NPDES permits for TVA plants in Tennessee now require that TVA submit CCR impoundment closure plans.[766] This is an important step in the right direction, but it does not go far enough. These closure plans are not required until after the permits' effective dates, and there is no avenue for public participation. Furthermore, although the Tennessee TVA permits require closure plans, they do not require specific closure BMPs. In order to ensure that CCR impoundments nationwide are subject to adequate and consistent conditions for safe closure, EPA must require specific design, maintenance and remediation criteria similar to the closure requirements for CCR surface impoundments proposed under RCRA. Where CCR is left in place, EPA must require closure plans with minimum safeguards including provisions for major slope stability, groundwater monitoring, cap-and-cover requirements, provisions to preclude the probability of future impoundment of water, and post-closure care.

XII. THE CLEAN WATER ACT DOES NOT SUPPORT EPA'S PROPOSED VOLUNTARY INCENTIVES PROGRAM.

The Tier 1 and Tier 2 voluntary incentive programs proposed by EPA are not supported by the Clean Water Act. EPA has proposed establishing, as part of the BAT for existing sources, a voluntary incentive program that provides more time for plants to implement the proposed BAT requirements if they adopt additional process changes and controls that provide environmental protections beyond those achieved by the preferred options for this proposed rule.[767] According to EPA, the primary objective of this program is "to encourage individual power plants to install advanced pollution prevention technologies or make process changes that would further reduce releases of toxic pollutants to the environment beyond the limits that would be set by the

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[764] *See* EPA, Information Request Responses from Electric Utilities, *available at* http://www.epa.gov/osw/nonhaz/industrial/special/fossil/surveys/index.htm.

[765] The ELG ICR data were not used to estimate present volume of waste or storage capacity of CCR impoundments because of the lack of data for both active and inactive units due to CBI claims.

[766] *See, e.g.*, TDEC, NPDES permit No. TN0005428 for the Gallatin Fossil Plant (2012). Permits for the Bull Run, John Sevier, Johnsonville and Kingston Fossil Plants include the same requirement.

[767] 78 Fed Reg. at 34,467.

proposed rule."[768] EPA claims the development of these advanced process changes and controls is "a critical step toward the Clean Water Act's ultimate goal of eliminating the discharge of pollutants into the Nation's waters."[769]

EPA's voluntary incentives program, however, conflicts with the mandatory three-year deadline for compliance with revisions to ELGs set forth in section 301(b)(2)(B).[770] To make matters worse, EPA's proposal contains no deadline for compliance with Tier 1 and Tier 2 requirements.[771]

The Tier 1 and Tier 2 programs are also ill conceived and will fail to achieve their stated objectives. The Agency's Tier 1 proposal is contrary to statutory intent, because instead of encouraging utilities to execute technologies that the industry otherwise would not be required to do, it makes an end run around conventional solid waste closure requirements that the Agency should mandate in this rulemaking or pursuant to RCRA in the CCR rule. CWA Section 104(a)(1) only authorizes programs that promote "the acceleration" of "research, investigations, experiments, training, demonstrations, surveys and studies" that prevent, reduce, or eliminate pollution. Establishing a voluntary incentives program that substantially delays industry compliance with BAT in exchange for completion of an activity that should be mandated under the ELG or CCR rules does not fall within the scope of a national program intended to encourage research, investigations, training and information pursuant to Section 104 of the Act.[772] In addition, the Tier 2 program will not achieve elimination of power plant discharges because it does not address leaking impoundments, groundwater discharges with a hydrogeological connection with surface waters, and legacy wastewaters, and because it places the burden on the permitting agency to develop individual discharge limits.

A. EPA MAY NOT WAIVE COMPLIANCE WITH THE REVISED ELGS BEYOND THE THREE-YEAR STATUTORY DEADLINE IN EXCHANGE FOR PARTICIPATION IN A VOLUNTARY PROGRAM.

The Clean Water Act mandates compliance with revisions to ELGs no later than three years from the effective date of the final rule.[773] Under the voluntary incentives program, participating plants would receive an additional two or five years (depending on the program) from the already lengthy compliance deadline[774] to comply with the ELGs.[775] EPA cites to section 104(a)(1) of the Act for its authority to establish its voluntary incentives program, which gives EPA "authority to establish national programs for prevention, reduction, and elimination of pollution, and . . . provides that such programs shall promote the acceleration of research, experiments, and demonstrations relating to the prevention, reduction, and elimination of

[768] *Id.* at 34,467.
[769] *Id.* at 34,467.
[770] 33 U.S.C. § 1311(b)(2). *See infra* Section XV.
[771] 78 Fed. Reg. at 34,467-34,468.
[772] *See* 33 U.S.C. § 1254(a)(1).
[773] 33 U.S.C. § 1311(b)(2). *See infra* Section XV.
[774] *See infra* Section XV.
[775] 78 Fed. Reg. at 34,467-34,468.

pollution."[776] Yet this provision does not allow EPA to waive the three-year compliance deadline.[777]

To further frustrate the goals of the Clean Water Act, EPA's proposal does not set a timetable for achievement of Tier 1 and Tier 2 goals.[778] Under both programs, permitting agencies would be responsible for including Tier 1 and 2 requirements in NPDES permits and determining when those requirements would be met.[779] Specifically, EPA states that "[o]nce a power plant enrolls in the [Tier 1 or Tier 2] program, the NPDES permitting authority would develop specific discharge limits and key milestones consistent with that tier."[780] There is no deadline specified for compliance with program requirements. And as discussed previously, permitting agencies have consistently failed to comply with the *statutory mandate* to set case-by-case BAT limits for power plants.[781] There is no reason to believe that states will now act promptly to set individual limits and deadlines for a voluntary program. Thus, EPA's voluntary program effectively waives compliance with statutory deadlines in exchange for vague promises to achieve Tier 1 and Tier 2 requirements at some later date in the future.

B. THE TIER 1 VOLUNTARY INCENTIVES PROGRAM IMPROPERLY OFFERS INDUSTRY SUBSTANTIAL ADDITIONAL TIME FOR IMPLEMENTATION OF BAT IN EXCHANGE FOR ACTIVITIES THAT SHOULD BE MANDATED BY THE RULE.

According to EPA, the Tier 1 program "would effectively accelerate the research into and use of controls and processes intended to prevent, reduce, and eliminate pollution because it would increase the number of plants choosing to close and cap CCR surface impoundments and eliminate discharges of all process wastewater (except cooling water) to surface waters." Under Tier 1, power plants would be granted two additional years to comply with BAT if they dewater, close and cap all CCR surface impoundments (except for those impoundments containing only combustion residual leachate) at the facility, including those surface impoundments located on nonadjoining property that receive CCRs from the facility.

It is inappropriate, however, to use a voluntary incentives program to encourage industry to do what should be mandated under RCRA or CWA. EPA has the authority to impose such closure requirements in BMPs for the ELG rule, as described in Section X of our comments, or in a CCR rule under RCRA. In its 2010 proposed CCR rule, EPA does in fact mandate the closure of surface impoundments under both the subtitle C and subtitle D proposal

In the subtitle C proposal, all CCR surface impoundments would be subject to closure performance standards set forth in 40 C.F.R. § 265.111 and § 265.228 pursuant to proposed 40 C.F.R. § 265.1300(b).[782] Pursuant to that rule, all surface impoundments that cease receiving CCRs would be subject to closure requirements that include: (1) removal or decontamination of

[776] *Id.* at 34,467 (citing 33 U.S.C. § 1254(a)(1)).
[777] *See* 33 U.S.C. § 1254(a)(1).
[778] 78 Fed. Reg. at 34,468.
[779] *Id.*
[780] *Id.*
[781] *See supra* Section III.D; *infra* Section XV.
[782] 75 Fed. Reg. at 35,258.

all waste residues, contaminated containment system components (liners, etc.), contaminated subsoils, and structures and equipment contaminated with waste and leachate; or (2) elimination of free liquids by removing liquid wastes or solidifying the remaining wastes; stabilization of remaining wastes to a bearing capacity sufficient to support the final cover; and cover of the surface impoundment with a cover designed and constructed to provide long-term minimization of the migration of liquids.[783] Furthermore, subtitle C requires that surface impoundments initiate closure within 90 days of receiving the final volume of waste.[784] Closure must be completed within two years after placement of waste in the existing impoundment ceases.[785] Finally, the proposed subtitle C rule also imposes post-closure monitoring and maintenance requirements.

EPA's proposed subtitle D rule similarly requires closure of a CCR surface impoundment by either removing and decontaminating all areas affected by releases from the impoundment or by closing with CCRs in place and requiring elimination of free liquids by removing liquid wastes, solidifying and stabilizing the remaining wastes, and installing a cover.[786] The timeframe for closure under subtitle D is no later than 30 days after the date on which the impoundment receives the final delivery of coal ash or, if the surface impoundment has remaining capacity and there is a reasonable likelihood that the impoundment will receive additional coal ash, no later than one year after the most recent receipt of waste.[787] The subtitle D rule also mandates requirements for post-closure monitoring and maintenance.[788] There is no reason to offer industries incentives—which allow continued discharges that are detrimental to health and the environment—in exchange for performing reasonable closure activities that they should be mandated by rule to perform, and which, in fact, have already been proposed three years ago in the CCR rule. Regardless of whether EPA finalizes the CCR rule with subtitle C or subtitle D requirements, facilities participating in the Tier 1 incentive program would be granted extensions for compliance with their BAT obligations in exchange for performing a mandated action.

Furthermore, the outcome of the Tier 1 voluntary incentive program would be directly contrary to the directive of CWA Section 104(a)(1). The intent of the Act is to establish such programs to accelerate technologies and provide incentives for industry to find new ways to reduce or eliminate pollution. In this case, however, the technologies for closure are clear and well established. There is no evidence in the record that dewatering and stabilizing a surface impoundment involves engineering that has not already been tested, proven and employed at solid waste surface impoundments for decades. Closure of hazardous waste impoundments was mandated by RCRA subtitle C, and closure of such impoundments have resulted in wide-scale testing of RCRA standards since the 1990s.

Lastly, the technological approach in the Tier 1 voluntary incentives program is contrary to the goals of CWA Section 104(a)(1) because it promotes remedial action that does not represent the cleanest and safest option for human health and the environment. Tier 1 encourages dewatering

[783] *See* 40 C.F.R. § 265.228(a).
[784] *See id.* § 265.113.
[785] *See id.* § 268.14, 75 Fed. Reg. at 35,262.
[786] *See* 40 C.F.R. § 257.100, 75 Fed. Reg. at 35,252.
[787] *See* 40 C.F.R. § 257.100(j), 75 Fed. Reg. at 35,252.
[788] *See* 40 C.F.R. § 257.101, 75 Fed. Reg. at 35,253.

and stabilizing coal ash in a permanent disposal unit, rather than removal and thorough decontamination of the site. The most environmentally-protective solution for coal ash surface impoundments is removal of all waste from the unit. This is the only method that guarantees the long-term health of the site and surrounding waters. In fact, even under EPA's proposed subtitle D rule, an owner/operator who closes a coal ash impoundment by removal and decontamination must ensure that coal ash contaminants throughout the impoundment and all areas affected by releases from the impoundment do not exceed numeric cleanup levels for those constituents.[789] Promotion of a lesser cleanup option has no place in EPA rules or in voluntary options.

C. THE TIER 2 PROGRAM GIVES INDUSTRY AN ADDITIONAL FIVE YEARS TO COMPLY WITH BAT LIMITATIONS IN EXCHANGE FOR PARTICIPATION WITH A PROGRAM THAT WILL NOT ELIMINATE ALL POWER PLANT DISCHARGES.

The Tier 2 program is also fundamentally flawed. Under Tier 2, power plants would be allowed five additional years to comply with BAT requirements "if they eliminate the discharge of all process wastewater to surface waters, with the exception of cooling water discharges."[790] EPA states that "[t]his program would give power plants a platform to advance the research and developmental technologies and processes that promote water conservation and water recycling and provide greater environmental protection."[791] In addition, this program places the burden on states to develop interim discharge limits.

The Tier 2 program claims to promote the "power plant of the future," by requiring the elimination of discharges and recycling of wastewater to limit the use of water. However, Option 5, which is BAT for existing sources, goes a long way towards achieving this goal. In addition, the program requirements don't address closure of leaking impoundments, groundwater to surface water discharges, and legacy wastewater—all of which cause damage to surface waters. In order to achieve the objective of the Tier 2 program (i.e., elimination of power plant discharges), these sources of surface water pollution must also be addressed.[792]

In addition, Tier 2 places a heavy burden on permitting agencies to develop "specific discharge limits and key milestones" for program requirements.[793] Yet permitting agencies have consistently failed to set case-by-case BAT limits mandated by the Clean Water Act and timely renew power plant NPDES permits.[794] In many cases, permitting agencies lack the resources and expertise to make these determinations.[795] Thus, a voluntary program that relies on permitting agencies to execute the Tier 2 program and set case-by-case discharge limits to achieve program goals is ill-conceived.

[789] *See* 40 C.F.R. § 257.100(b); 75 Fed. Reg. at 35,252.
[790] 75 Fed. Reg. 34,468. "The Tier 2 incentives would not be available to power plants that eliminate direct discharge to surface water by sending the wastewater to a POTW." *Id.*
[791] *Id.*
[792] *Id.*
[793] 75 Fed. Reg. at 34,468.
[794] *See supra* Section III.D; *infra* Section XV.
[795] *See supra* Section III.D.

D. D. EPA SHOULD NOT DEVELOP VOLUNTARY STANDARDS THAT LACK ENFORCEABILITY, TRANSPARENCY, AND THE OPPORTUNITY FOR PUBLIC PARTICIPATION.

EPA's proposal is unclear concerning the extent to which voluntary standards would be incorporated into enforceable permit conditions and whether the public would have the opportunity to comment on such conditions. As stated above, state permitting agencies have routinely failed to set case-by-case BAT limits, so it cannot be left to chance whether the voluntary programs are executed in a manner that preserves enforceability, transparency and public participation in decision-making. It is clear that these are not guaranteed by the voluntary incentives program.

XIII. INDUSTRY MUST COMPLY WITH THE FINAL ELGS NO LATER THAN THREE YEARS FROM THE DATE WHEN THE RULE IS FINALIZED.

Americans have already waited over thirty years for EPA to control dangerous discharges from power plants. Although EPA is finally taking action to curb power plant water pollution, the compliance schedule EPA proposes would allow facilities to delay clean-up for at least another eight years and fails to include a firm deadline for compliance. The Clean Water Act, however, mandates compliance with revised ELGs no later than three years from the date the revisions are finalized.[796] As a practical matter, facilities can comply with revised ELGs within this statutory time frame, and there is no excuse for further delay. EPA must require compliance with the ELGs as soon as possible, but in no case later than three years from the effective date of the rule.

A. THE CLEAN WATER ACT REQUIRES COMPLIANCE WITH REVISED ELGS NO LATER THAN THREE YEARS FROM THE DATE THE REVISIONS ARE FINALIZED.

The Clean Water Act states that compliance with BAT limitations promulgated under section 304(b) shall be "as expeditiously as practicable, but in no case later than three years after the date such limitations are promulgated . . . , and in no case later than March 31, 1989."[797] Section 304(b) of the Clean Water Act directs EPA to "provid[e] guidelines for effluent limitations, and, at least annually thereafter, *revise*, if appropriate, such regulations."[798] Thus, the plain language of the statutory provision states that compliance with initial regulations must occur within three years of promulgation and in no case later than March 31, 1989 and compliance with revised ELGs must occur within three years.

To read section 304(b) as only imposing a deadline for compliance with initial promulgation of ELGs is contrary to the goals of the Clean Water Act and would allow industry to evade timely compliance with regulations that EPA must review and revise at regular intervals to ensure

[796] 33 U.S.C. § 1311(b)(2)(C), -(D).
[797] 33 U.S.C. § 1311(b)(2)(C), -(D).
[798] *Id.* § 1314(b) (emphasis added).

maximum reductions in effluent discharges on a mandatory schedule.[799] It is a well-established principle of statutory interpretation that "'[i]n ascertaining the plain meaning of [a] statute, the court must look to the particular statutory language at issue, as well as the language and design of the statute as a whole.'"[800] Courts also look to the title of a statute or section to aid in resolving an ambiguity in the legislation's text.[801]

Congress passed the Clean Water Act in 1972 "to restore and maintain the chemical, physical, and biological integrity of the Nation's waters."[802] The Act protects all waters of the United States, including surface waters that supply drinking water, support fish and wildlife, and provide aesthetic and recreational opportunities for current and future generations of Americans. The Clean Water Act's goal is to eliminate all discharges of pollution into navigable waters.[803] To achieve this goal, the Act requires that EPA set effluent limits based on BAT for pollutants including toxic metals.[804] To facilitate the adoption and revision of effluent limitations, the Act also requires that EPA develop and publish ELGs that characterize the effluent discharges from a given industry, identify the level of pollution control that is possible in light of available technologies, and specify the relevant factors for determining what constitutes BAT.[805]

To ensure that governing regulations reflect advances in control technology, the Clean Water Act requires EPA to review and, if appropriate, revise these effluent limitations and underlying ELGs at regular intervals.[806] Section 301(d) of the Clean Water Act requires that all effluent limitations "*shall* be reviewed at least every five years, and, if appropriate, revised."[807] Similarly, with respect to ELGs, section 304(b) of Clean Water Act requires that "the Administrator *shall* . . . publish . . . regulations, providing guidelines for effluent limitations, and, at least annually thereafter, revise, if appropriate, such regulations."[808] These sections impose mandatory obligations on EPA to take action within the statutory deadlines.

Furthermore, the title of section 1311(b) is "Timetable for achievement of objectives," and the first sentence of section 1311(b) begins "In order to carry out the objective of this chapter…" (i.e. Federal Water Pollution Control Act).[809] The title of section 301(b) is further support that Congress intended the compliance timetables to further all CWA objectives, including reductions

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[799] *See, e.g.*, *McCarthy v. Bronson*, 500 U.S. 136, 139 (1991) ("'In ascertaining the plain meaning of [a] statute, the court must look to the particular statutory language at issue, as well as the language and design of the statute as a whole.'") (quoting *K Mart Corp. v. Cartier, Inc.,* 486 U.S. 281, 291 (1988)).
[800] *McCarthy v. Bronson*, 500 U.S. 136, 139 (1991) (quoting *K Mart Corp. v. Cartier, Inc.,* 486 U.S. 281, 291 (1988). *See also Crandon v. United States*, 494 U.S. 152, 158 (1990) ("In determining the meaning of the statute, we look not only to the particular statutory language, but to the design of the statute as a whole and to its object and policy").
[801] *INS v. National Center for Immigrants' Rights*, 502 U.S. 183, 189-90 (1991) (citing *Mead Corp. v. Tilley*, 490 U.S. 714, 723 (1989)).
[802] 33 U.S.C. § 1251(a).
[803] *See* 33 U.S.C. § 1251(a)(1).
[804] *See* 33 U.S.C. §§ 1311(b)(2)(A)-(F), 1314(a)(4).
[805] *Id.* § 1314(b).
[806] *See* 33 U.S.C. §§ 1311(d), 1314(b).
[807] 33 U.S.C. § 1311(d) (emphasis added).
[808] 33 U.S.C. § 1314(b) (emphasis added).
[809] 33 USC § 1311(b).

in pollution discharges from the mandatory revision of, and compliance with, ELGs and effluent limitations at regular intervals.[810]

In short, Congress' goal in enacting the Clean Water Act was to produce progressively cleaner waters—and ultimately eliminate all pollution—through the ratcheting down of effluent limits over time as technology advances .[811] Mandatory revisions to standards with no deadline for compliance with those standards would be meaningless. An interpretation of section 301(b)(2) that does not impose a three-year outer bound on compliance with revisions of these limits is clearly contrary to the language and design of the Clean Water Act.

B. EPA MUST SET A THREE-YEAR DEADLINE FOR COMPLIANCE WITH THE BAT REQUIREMENTS IN THE FINAL RULE.

Under the plain meaning of Section 301(b)(2), the final rule must state that compliance with new requirements must occur no later than three years from its effective date.[812] Currently, the proposed rule contains no hard deadline for compliance. EPA states that BAT limitations for existing sources "would apply on a date determined by the permitting authority that is as soon as possible when the next permit is issued beginning July 1, 2017."[813] EPA estimates that "all steam electric facilities will have the proposed BAT limitations applied to their permits no later than July 1, 2022."[814] However, EPA ignores the fact that state permitting agencies routinely fail to renew NPDES permits for power plants in a timely manner even though the Clean Water Act requires discharge permits to be renewed every 5 years.[815]

Contrary to EPA's judgment, it is unlikely that all power plants would have the rule's new BAT requirements incorporated into their permit no later than July 1, 2022 because the reality is that many discharge permits for power plants are administratively extended well beyond five years. A recent report released by the Environmental Integrity Project, Sierra Club, Earthjustice, Waterkeeper Alliance, and Clean Water Action found that almost half (187) of 382 power plants were operating with expired permits as of March 13, 2013.[816] Nearly 30% of the expired permits had expired five or more years ago.[817] For example, the permit for the FirstEnergy Mitchell plant in Washington County, Pennsylvania expired in 1996—almost *20 years* ago.[818] Given past practices, EPA simply cannot rely on state permitting agencies to ensure BAT requirements are in place by a date certain without imposing a hard deadline in the final rule. As discussed above, the Clean Water Act requires compliance within three years of the effective date of the final rule.

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[810] 33 U.S.C. § 1311(d) (emphasis added).
[811] 33 USC § 1251(a)(1), (2), (6).
[812] Previous ELGs have set a firm date for compliance. *See e.g.*, Copper Forming Point Source Category; Effluent Limitations Guidelines, Pretreatment Standards, and New Source Performance Standards, 48 Fed. Reg. 36,942 (Aug. 15, 1983) (noting that "[t]he compliance date for the BAT regulations is as soon as possible, but in any event, no later than July 1, 1984.").
[813] 78 Fed. Reg. at 34,479.
[814] *Id.* at 34,480.
[815] 33 U.S.C. § 1342(b)(1)(B).
[816] Environmental Integrity Project et al., Closing the Floodgates: How the Coal Industry is Poisoning Our Water and How We Can Stop It 9 (July 23, 2013), *available at* http://www.environmentalintegrity.org/news_reports/07_23_2013.php.
[817] *Id.* at 10.
[818] *Id.* at 41.

EPA should state in the final rule that compliance is required with the new BAT requirements "as soon as possible, but no later than three years from the effective date of the final rule."

C. THE RECORD DOES NOT SUPPORT EPA'S CONTENTION THAT SOME SOURCES ARE NOT ABLE TO COMPLY WITH NEW BAT REQUIREMENTS WITHIN THREE YEARS.

The record does not demonstrate that facilities cannot comply with new BAT requirements within three years of the effective date of the rule. While acknowledging that some facilities could meet the new BAT requirements "relatively quickly," EPA notes that it is proposing such a lengthy compliance schedule because "[s]ome facilities will need time to raise the capital, plan and design the system, procure equipment, construct and then test the system" and "providing a window of time will better enable facilities to install the pollution control technology during an otherwise planned shutdown or maintenance period."[819]

Yet the record and available information do not support EPA's rationale for the lengthy compliance deadline. For example, with respect to bottom ash dry handling systems, "the lead time to design, build, and install these units is typically 1 to 2 years,"[820] which is well within the statutory timeframe for compliance with revised BAT requirements. The construction schedule for conversion to a dry bottom ash handling system at the Mayo plant in North Carolina, for example, is one year.[821] Furthermore, the installation of these technologies requires minimal outage time.[822] Additionally, the installation of FGD wastewater and leachate treatment systems will not require lengthy downtimes because these systems do not involve the boilers directly.[823] Their installation therefore need not be timed with otherwise planned shutdown and maintenance periods. In fact, the construction schedule for the FGD mechanical evaporation system for the Mayo plant shows that it will take only 18 months from the start of the construction to complete testing of the system.[824]

D. AMERICANS SHOULD NOT BE FORCED TO WAIT ANOTHER DECADE FOR CLEAN WATER.

The utility industry—the nation's largest discharger of toxic pollution—has effectively been given a free pass to pollute for over thirty years, which has resulted in widespread damage to

[819] 78 Fed. Reg. at 34,479-34,480.
[820] Fox Report, Appendix E, at 15. *See also* Dennis Del Vecchio et al., Wet to Dry Bottom Ash Disposal Conversion Project - BL England Station, Power-Gen (Dec. 2011), *available at* http://www.naes.com/sites/default/files/documents/delvecchio_speaker10835_session1236_2.pdf; Dry Bottom Ash System Installation Unit NR IV of Ptolemaida Power Station, (Project duration 8/1/94 to 8/31/96), *available at* http://cordis.europa.eu/opet/fiches/ff-20.htm; *See also* Email from Bret Renfroe to Ronald Powell Re KIF Dry Fly Ash Collection (Dec. 15, 2003) (noting 24 month installation time for similar dry fly ash system), *available at* http://www.tva.com/kingston/tdec/pdf/TVA-00013864.pdf.
[821] Construction Schedule for EMC SOC WQ S10-012, Mayo Steam Electric Plant, NPDES Permit No. NC0038377.
[822] *See* Fox Report, Appendix E.
[823] *See supra* Section III.
[824] Construction Schedule for EMC SOC WQ S10-012, Mayo Steam Electric Plant, NPDES Permit No. NC0038377.

watersheds around the country and put downstream communities in harm's way.[825] Coal water pollution raises cancer risks, makes fish unsafe to eat, can inflict lasting brain damage on our children, and poisons our rivers, lakes, and streams.[826] EPA is finally taking long overdue action to curb these dangerous discharges, but is allowing industry at least 8 years[827] to comply with new requirements and is proposing to exempt cleanup of legacy wastewaters.[828]

EPA's proposal to delay full compliance until 2022 instead of requiring compliance with the new requirements within the three-year statutory timeframe could result in the dumping of an additional *27.5 billion pounds* of pollution into U.S. waters.[829] The additional delay will also allow plants to continue dumping waste into unsafe and leaking surface impoundments for several more years, which will only worsen the problems associated with EPA's proposed exemption of legacy wastewaters. The Clean Water Act mandates cleanup and there is no excuse for further delay. For all of these reasons, EPA must require compliance with the requirements in the final rule as soon as possible, but no later than three years from the effective date of the final rule.

XIV. THE CLEAN WATER ACT OBLIGATES EPA TO SET BAT LIMITS FOR DISCHARGES OF EXISTING WASTES.

The Clean Water Act requires EPA to identify the reduction of toxic pollutants achievable through the use of the best technology – without regard to when the pollutants were generated. EPA has no authority to promulgate BAT guidelines that exempt existing wastes, as EPA is proposing to do. Under all proposed options, for all waste streams, the new BAT and PSES requirements would apply only to wastewater generated after a date that is later than July 1, 2017 and is determined by the state permitting authority.[830] Moreover, the proposal contemplates going one step further and establishing separate BAT limits for legacy wastewater that are equal to the current BPT limits.[831] Both of these proposals would violate EPA's statutory duty to promulgate BAT guidelines for discharges of pollutants without regard to when the pollutants were generated.

A. SEVERAL SYSTEMS ARE TECHNOLOGICALLY AND ECONOMICALLY ACHIEVABLE FOR TREATING EXISTING FGD WASTES AND LEACHATE STORED IN SEPARATE IMPOUNDMENTS.

Several treatment systems are technologically and economically achievable for dramatically reducing the toxicity of existing FGD wastewater and leachate that has been stored in separate

[825] *See generally* EA, *see supra* Section I.
[826] *See* 3-30, 5-1 to 6-48.
[827] As discussed in this section, EPA's estimate that all plants will come into compliance with the new requirements by 2022 is overly optimistic as states routinely fail to timely renew power plant discharge permits.
[828] 78 Fed. Reg. at 34,522-34,523.
[829] *See* EA at 3-3 tbl. 3-2 (estimating that the Steam Electric industry discharges 5.5 billion pounds of pollution each year).
[830] 78 Fed. Reg. 34,522-23.
[831] *E.g.*, *id.* at 34,523, 34,461.

impoundments.[832] However, EPA did not evaluate any of these treatment systems because it assumed, with no evidence, that most facilities send FGD and leachate wastewater to impoundments containing multiple waste streams. According to the Agency, the data supporting the BAT limits for the separate waste streams do not necessarily apply to the co-mingled waste streams, so EPA cannot evaluate whether the BAT limits would also represent BAT for the co-mingled waste in the impoundments.[833]

However, EPA acknowledges that 22% of facilities generating FGD wastewater send the wastewater to an impoundment containing only FGD wastewater.[834] Similarly, EPA notes that some facilities (EPA does not say how many) send leachate to small impoundments containing only leachate.[835] Moreover, in describing the various ways facilities could configure their treatment systems to comply with the new BAT requirements, EPA has included diagrams of systems that run both newly generated and legacy FGD wastewater through the treatment system that would be used to meet the new BAT requirements.[836] In fact, running legacy FGD wastewater through the biological treatment system would reduce the variability in FGD wastewater flow rates, allowing constant flow through the treatment system even during plant outages and maintenance periods.

As explained previously, treatment systems are technologically and economically achievable for eliminating the discharge of (or at least reducing the toxicity of) FGD wastewater and leachate.[837] Whatever system EPA ultimately selects as BAT for newly generated FGD wastewater and leachate must apply equally to existing wastes stored in separate impoundments, or where an impoundment contains only those two wastewaters.[838]

EPA has not advanced a credible technical or legal rationale for doing otherwise. To the extent that the FGD wastewater or leachate is stored in a separate impoundment, the treatment technology will work exactly the same on existing wastes as it will work on newly generated waste. Nothing will happen in 2017 to change the way the treatment systems work on these waste streams – if they will work in 2017 on newly generated wastes, they will perform equally well on existing wastes stored in separate impoundments. Put differently, there is no support in the record for claiming that the technological or economic achievability of treatment systems is affected by when the pollutants were generated – so long as the pollutants in a waste stream are stored in a separate impoundment and not co-mingled.

Legally, EPA has both the authority and the obligation to establish BAT guidelines that eliminate the discharge of pollutants for categories of sources – even if that category is smaller than the entire industry. Effluent limitations shall be achieved for "categories and classes of point

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[832] *See supra* Sections III, VI (discussion of treatment systems for FGD and leachate waste streams).
[833] 78 Fed. Reg. at 34,461, 34,463.
[834] *Id.* at 34,461.
[835] *Id.* at 34,463.
[836] TDD at 14-4, Figure 14-1.
[837] *See supra* Sections III, VI.
[838] As explained in the leachate report of Dr. David Jenkins, Appendix D, and as verified by the performance of the biological treatment system at the Mountaineer plant, leachate and FGD wastewater can be treated together in the chemical precipitation and biological treatment systems. Thus, where legacy FGD wastewater and leachate have been co-mingled, there is no technological barrier to treating these wastes in the biological system.

sources."[839] The effluent limitations "shall require the elimination of discharges of all pollutants" if EPA finds that "such elimination is technologically and economically achievable for a category or class of point sources."[840] The statute mandates a zero discharge standard if achievable for a "category or class."[841] Even if a zero discharge standard is not achievable, the effluent limitations must require the best available technology economically achievable "for such category or class."[842] Similarly, EPA must identify "the degree of effluent reduction attainable" through the best control measures "for classes and categories of point sources."[843]

EPA has identified a class of facilities that can eliminate the discharge of FGD wastewater and leachate, or, at a minimum, can treat such wastes with various technologies. That class is the 22% of plants that store FGD wastewater in separate impoundments and the class of plants that store leachate in separate impoundments. Whatever technology is selected as BAT for newly generated FGD wastes and leachate must apply equally to existing FGD wastes and leachate at these plants that store their wastes in separate impoundments. Moreover, since co-mingled FGD wastes and leachate are amenable to chemical and biological treatment, BAT for legacy FGD wastes and leachate co-mingled in an impoundment should be chemical and biological treatment.

B. EPA MUST CONSIDER TECHNOLOGIES FOR ELIMINATING THE DISCHARGE OF, OR TREATING, CO-MINGLED WASTES.

EPA offers a different rationale for fly ash and bottom ash transport water. For those waste streams, EPA is proposing to choose between the current BPT requirements and zero discharge systems. The Agency notes that if dry ash handling is BAT, dry ash handling obviously does not treat existing wastewater.[844] That of course is true, but begs the question of whether other technologies exist that could treat the existing fly ash and bottom ash wastewater, whether stored separately or co-mingled in impoundments. EPA never addresses that question.

As mentioned above, effluent limitations "shall be achieved" for toxic pollutants "for categories and classes of point sources."[845] EPA must issue guidelines that identify "the degree of effluent reduction attainable" through the best control measures "for classes and categories of point sources."[846] EPA has an obligation to identify the reductions attainable for toxic pollutants discharged by point sources regardless of whether those pollutants are stored separately or co-mingled. The statute does not give EPA a free pass for legacy or co-mingled waste streams.

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[839] 33 U.S.C. § 1311(b)(2)(A).
[840] *Id.*
[841] *Id.*
[842] *Id.*
[843] *Id.* § 1314(b)(2)(A). Congress modified the BAT requirements for the coal remining industry so that BAT for pre-existing discharges would be determined by the relevant permitting authority on a case-by-case basis using BPJ, rather than by EPA on a nation-wide basis. 42 U.S.C. § 1311(p)(1). The pre-existing discharge provision does not exempt the coal remining industry from BAT – instead, it only changes who determines BAT, and how—and applies only to a single industry, coal remining. Congress did not extend similar relief to other industries, such as power plants. Furthermore, the provision applies to pre-existing discharges, not pre-existing waste, further supporting the view that Congress did not intend to exempt the discharge of pre-existing wastes from the BAT requirements.
[844] 78 Fed. Reg. at 34,461-62.
[845] 33 U.S.C. § 1311(b)(2)(A).
[846] *Id.* § 1314(b)(2)(A).

EPA has failed to meet its obligation, and has instead simply decided not to investigate whether there are controls and practices that can reduce pollutants stored in impoundments containing co-mingled waste streams. Chemical precipitation followed by biological treatment can be used for co-mingled FGD wastes and leachate.[847] Additionally, EPA evaluated chemical precipitation for ash handling, but rejected the technology because of its purportedly high cost relative to dry handling, not its technical feasibility.[848] This suggests that systems are available for treating ash transport water in existing impoundments. Moreover, chemical precipitation is effective at treating leachate,[849] which comes from co-mingled wastes in impoundments; and chemical precipitation, followed by biological treatment, is effective at treating at least certain kinds of co-mingled wastes, such as FGD wastes and leachate.[850] Taken together, the record suggests that systems may be technologically and economically achievable for treating legacy ash wastes, even when co-mingled with other waste streams. We urge EPA to identify the best technology for reducing discharges of existing wastes that are stored separately or co-mingled in impoundments.

XV. EPA'S INTEGRATION OF THE ELG AND CCR RULES MUST CONSIDER THE NATURE AND SCOPE OF THE RISKS POSED BY COAL COMBUSTION RESIDUALS TO HUMAN HEALTH AND THE ENVIRONMENT.

EPA's efforts to "align" the proposed ELG and CCR rules make consider the distinct and significant risks posed by each pollution source. Use of data from the 2010 ELG surveys can enhance understanding of the risks posed by coal ash, but there is also a danger that the data will be misused. In fact, EPA's proposed use of several data sets is likely to underestimate significantly the risk to human health and the environment from improperly managed coal ash. Further, EPA appears in this proposed rule and in the coal ash Notice of Availability that preceded it, to be ignoring ELG survey data that show distinctly increased risk from coal ash. The desired "alignment" of the rules must not take precedence over the goal of protecting health and the environment from all risks posed by power plant wastes.

A. FOREMOST EPA MUST ENSURE THAT THE ELG AND CCR RULES FULFILL THE MANDATES OF THE CLEAN WATER ACT AND THE RESOURCE CONSERVATION AND RECOVERY ACT.

In the preamble to the proposed ELG rule, EPA acknowledged the intersection between the CCR and ELG rules and expressed the need to "align and structure" the CCR rule to account for any final requirements adopted under the ELG rule.[851] According to EPA, the Agency's goal in the dual rulemaking process is "to ensure that the two rules work together to effectively address the discharge of pollutants from steam electric generating facilities and the human health and environmental risks associated with the disposal of CCRs, without creating avoidable or

[847] *See* Jenkins Leachate Report, Appendix D.
[848] 78 Fed. Reg. at 34,461.
[849] *See* discussion of BAT for leachate, *supra* Section VI.
[850] *See* Jenkins Leachate Report, Appendix D.
[851] 78 Fed. Reg. at 34,441.

unnecessary burdens."[852] First and foremost, EPA emphasized, the agency must fulfill its statutory mandate to restore and maintain water quality under the CWA and to protect human health and the environment under RCRA."[853]

To that end, EPA proposed two primary means of integrating the ELG and CCR rules:

> (1) through coordinating the design of any final substantive CCR [sic] regulatory requirements [with ELG requirements], and (2) through coordination of the timing and implementation of final rule requirements to provide facilities with a reasonable timeline for implementation that allows for coordinated planning and protects electricity reliability for consumers.[854]

Thus the first method of integration involves the design and substance of the requirements, and the second involves coordinating their timing. Under both means of "alignment," EPA must consider the risks specific to CCR and fulfill its duty to protect health and the environment under RCRA.

In implementing this two-tiered approach, however, EPA strayed from its statutory mandate. First, the Agency suggested that data gathered for the ELG rulemaking may necessitate significant revision of the draft CCR risk assessment and risk screening analysis for fugitive dust.[855] However, as explained below, EPA's proposed arbitrary use of data collected for the ELG rule would result in the gross underestimation of risk from CCRs. Second, in the guise of promoting coordinated timing and implementation, EPA failed to properly consider the risks posed by CCRs and the need to require timely compliance at high risk facilities.

B. EPA'S PROPOSAL TO USE A GROUNDWATER INTERCEPTION MODEL THAT GROSSLY UNDERESTIMATES RISK TO DRINKING WATER IS ARBITRARY AND CAPRICIOUS AND CONTRARY TO LAW.

EPA proposed in the preamble that the facility-specific data collected by EPA's Office of Water for the ELG rule could be used in EPA's risk assessment in ways that would significantly affect the results of that assessment.[856] Specifically, EPA noted that these data could be used to determine the extent to which plumes of contamination leaching from coal ash disposal units into groundwater are intercepted (and reduced) by surface water bodies that exist between a disposal unit and a down-gradient drinking water well. According to EPA, these data "would allow EPA to better estimate the contaminant levels that people would be expected to receive in drinking water, and to better model the likely environmental risks (e.g., to fish and other aquatic life) from such contaminants in surface waters."[857] EPA concluded that "because so many of the disposal units … are located next to rivers, the results of the interception analysis could reasonably be expected to have a significant impact on the risk assessment results."[858]

[852] *Id.*
[853] *Id.*
[854] 78 Fed. Reg. at 34,442.
[855] *Id.*
[856] *Id.*
[857] *Id.*
[858] *Id.*

There are several significant problems with the use of the data derived from the ELG rulemaking and with the use of a new mathematical procedure introduced in the recent CCR NODA that purports to determine the impact of these nearby surface water bodies.[859] EPA's use of the data ignores key factors that affect migration of CCR contaminants including infiltrating leachate-soil interactions, the effects of water table mounding or depletion on the direction of groundwater flow at the local scale, aquifer heterogeneities, and the presence of actual receptors that are likely impacted by the CCR waste management units. Detailed comments addressing these issue were submitted in response to the NODA and they are attached to these comments as Appendix XII-1, Remy Hennet, Ph.D., "Response to the Notice of Data Availability (NODA) and Request for Comment;" Appendix XII-2, Russ Boulding, "EPA's Proposed Modifications to the EPACMTP Model for Assessing Risk of Coal Combustion Residual Disposal Units to Groundwater and Surface Water Further Weaken an Already Flawed Risk Assessment;" Appendix XII-3, Charles Norris, "Geo-Hydro, Inc. Critique of EPRI CCW Risk Evaluation."

EPA must consider the complex interactions of groundwater flow, leachate development, and large waste deposits and examine the site-specific evidence that identifies risks and documents high levels of contaminants in groundwater at sites near large bodies of water, where such interactions have taken place. To ignore the evidence of groundwater contamination and the populations at risk at these sites is without rational basis and contrary to law. Blind adherence to a model that may describe contaminant behavior at some, but not all sites, fails to protect human health and the environment and ignores the voluminous record of damage contained in the CCR docket.

C. EPA'S USE OF CHEMICAL DATA SUBMITTED TO THE OFFICE OF WATER TO MODEL IMPACTS TO GROUNDWATER FROM CCR DISPOSAL UNITS IS ARBITRARY AND CAPRICIOUS AND WITHOUT RATIONAL BASIS, BECAUSE THE DATA ARE NOT REPRESENTATIVE OF LEACHATE FROM CCR LANDFILLS AND IMPOUNDMENTS.

The information in the ELG database pertaining to chemical data, while potentially relevant to determining the quality of water discharged directly to surface water, must not be used to revise the CCR risk assessment. The chemical data submitted in response to the questionnaire were not generated with the goal of being representative of the chemical diversity and variability of CCR disposal units. The reported data represent regulated effluents or monitoring points that have been selected for purposes unrelated to determining the nature of leachate entering groundwater from CCR landfills and impoundments.[860] These data cannot be directly compared with data that were acquired following the scientific method to characterize specifically the compositional

[859] Comments of Earthjustice et al. to U.S. EPA, Office of Resource Conservation and Recovery, Notice of Data Availability and Request for Comment (Coal Ash NODA), 78 Fed. Reg. 46,940 (Aug. 2, 2013) (comments filed Sept. 3, 2013) (Document ID No. EPA-HQ-RCRA-2012-0028-0111).

[860] *See* ELG Questionnaire, Part G, Leachate Sampling Data. "The untreated leachate samples must be collected directly from the leachate collection system or holding tank prior to any form of treatment." "If the [unit] has multiple collection points, the untreated sample may be collected from a common header area, if applicable. If there is not a common header area for the [unit], the plant may select one of the collections points that is "representative" of the [unit] from which to collect the sample. If warranted . . . the plant may need to collect samples from more than one collection point to obtain representative samples."

variability and diversity of environmental releases from CCR disposal units. Combining the ELG's treated and untreated leachate data with the CCR-specific leachate data in the risk assessment would be arbitrary and without rational basis.

Specifically, the use of the chemical data ignores the critical difference between pore water and leachate. There is almost never pore water collected as impoundment leachate, and impoundment water will almost invariably have lower concentrations of metals and other coal ash contaminants than pore water. The two primary reasons for the lower concentrations in discharged impoundment leachate are one-time and brief contact with CCR and dilution from precipitation and storm water runoff when the leachate is co-managed. In the case of the ELG chemical data, the industry responses indicate the leachate is often co-managed. Thus the leachate data represent low contaminant concentrations compared to the pore water data used in the CCR risk assessment.

In contrast, if a CCR waste disposal unit had a sub-waste leachate collection system and industry responders collected that leachate and analyzed it before treatment or mixing with other leachate or runoff, it would represent pore water within the landfill or impoundment. Without meeting *each* of these conditions, however, the sampled leachate does not represent pore water, and it will almost certainly be less concentrated than a pore water sample would be. There is no indication that any of the sampling data submitted by industry pursuant to the ELG questionnaire was undiluted pore water, because the questionnaire did not direct responders to analyze that type of sample.[861] EPA did not place the schematic diagrams or photos of the sampling points required by the questionnaire in the record, so commenters cannot consult these sources. EPA, however, can and must do so.

Commenters note that any water that comes in contact with CCR is "leachate," and while it is legitimate to identify the data submitted to EPA as "leachate," it is not "pore water" and therefore its application to the risk assessment must be scrutinized. For purposes of modeling groundwater impacts in the CCR risk assessment, only pore water should be used. If other forms of leachate are combined with the pore water data, gross underestimation of risk will result. For example, EPA cannot and must not conclude that the concentrations of arsenic and other contaminants in leachate reported in the industry responses to the questionnaire are representative of pore water, particularly for surface impoundments.

Further information on the need to use the ELG chemical data for the specific purpose for which it was collected and its inapplicability to the CCR risk assessment is found in Appendix XII-A and an exhibit attached to this comment letter.

D. EPA MUST CONSIDER INCREASED RISK FROM THE SUBSTANTIAL RISE IN THE NUMBER OF UNLINED AND INADEQUATELY LINED SURFACE IMPOUNDMENTS IDENTIFIED IN THE DATA GATHERED FOR THE ELG RULE.

EPA notes in the preamble to the ELG rule that new data submitted by industry provided information on the location, size, and the type of waste present in hundreds of CCR surface

[861] *Id.*

impoundments that were omitted from the data sources on which EPA relied to develop the proposed CCR rule. The increase in the number of known surface impoundments is substantial; the number of CCR surface impoundments increased 50 percent from 710 to 1,070 impoundments since 2010. EPA also noted that the newly identified impoundments were generally smaller than the impoundments included in the data used to support the proposed CCR rule. EPA, must however, look at factors beyond volume, which is not always determinative of the risk posed by CCR dumps.

EPA must consider a multitude of factors in addition to volume of CCR when determining risk to human health and the environment. According to EPA's Office of Research and Development, the extent of leaching from CCR disposal units involves the following critical controlling factors: chemical factors, physical factors and site conditions.[862] Chemical factors include equilibrium/kinetic control, pH, liquid-solid ration, complexation, redox, sorption and biological activities.[863] Physical factors include particle size and rate of mass transport.[864] Third, site conditions include flow rate of leachate, temperature, bed porosity, fill geometry, permeability and hydrological conditions.[865] These factors, as well as the proximity of sensitive receptors, have great impact on the risk posed by the release of hazardous substances from CCR disposal units.

In addition, the Agency must also consider the presence or absence of safeguards to prevent the migration of hazardous contaminants. The absence of composite liners at CCR surface impoundments is of great concern, and the widespread lack of barriers to stop contaminant migration must be factored into the risk assessment.[866] According to the draft risk assessment, only composite liners are effective in reducing the leaching of dangerous quantities of hazardous substances into underlying groundwater.[867]

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[862] *See* Susan Thorneloe, U.S. EPA, Office of Research and Development, "Use of Leaching Environmental Assessment Framework for future fly ash management decisions," presented at Workshop on Environmental Aspects of Coal Ash Uses, Tel Aviv, Israel (May 13, 2013). *See also* EPA, Office of Research and Development, *Characterization of Coal Combustion Residues from Electric Utilities—Leaching and Characterization Data* (EPA/600/R-09/151) at ii (Dec. 2009), *available at* http://www.epa.gov/nrmrl/pubs/ 600r09151/600r09151.html (citing EPA, *Characterization of Mercury- Enriched Coal Combustion Residuals from Electric Utilities Using Enhanced Sorbents for Mercury Control* (EPA–600/ R–06/008) (Feb. 2006), *available at* http://www.epa.gov/ORD/NRMRL/pubs/600r06008/600r06008.pdf; *and* EPA, *Characterization of Coal Combustion Residuals from Electric Utilities Using Wet Scrubbers for Multi-Pollutant Control* (EPA–600/ R–08/077) (July 2008), *available at* http://www.epa.gov/nrmrl/pubs/600r08077/600r08077.pdf.
[863] *Id.* at 10.
[864] *Id.*
[865] *Id.*
[866] Composite liners are defined as 60 mil HDPE membrane with either an underlying geosynthetic clay liner or a 3-foot compacted clay liner. A leachate collection system is also assumed to exist between the waste and the liner system. *See* U.S. Envtl. Prot. Agency, "Draft: Human and Ecological Risk Assessment of Coal Combustion Wastes,'' April 2010 (EPA–HQ–RCRA–2009–0640–0002), 3-21. In addition, the lower component must have a hydraulic conductivity of no more than 1x10(-7) cm/sec.
[867] According to the draft risk assessment, "For the groundwater-to-drinking-water pathway, composite liners, as modeled in this assessment, effectively reduced risks from all constituents to below a 10-5 cancer risk or HQ of 1 for both landfills and surface impoundments at the 90th and 50th percentiles." ES-5.

This should be of great concern to EPA, because the responses to the ELG questionnaire indicate with certainty that at least 61 percent of all surface impoundments lack composite liners.[868] However, the actual number of impoundments without composite lines may greatly exceed this number. Due to the lack of clarity of both EPA's questionnaire and the industry responses (9.5 percent of responders failed to answer the question, most responders did not provide a complete response, and some answers were contradictory), an exact count of surface impoundments lacking composite liners is impossible.[869] However, when one considers that a high-density polyethylene (HDPE) membrane is an essential component of a composite liner system, only 78 active surface impoundments in total (only 6.8 percent of surface impoundments) admitted to using a HDPE liner. The number diminishes even further when one considers the requirement that the HDPE liner be combined with a compacted clay liner and achieve minimum hydraulic conductivity. Based on these factors, the number of active surface impoundments meeting these criteria dwindles to *less than a dozen*, meaning that 99 percent of surface impoundments may lack protective composite liners. While the ambiguity of both the questionnaire and the responses prevent a precise count, it is certain that the overwhelming majority of operating surface impoundments lack the liners that are critical to protect human health and the environment. This must be taken into account in the revised risk assessment.

Lastly, EPA must amend the risk assessment to reflect the large increase in the number of CCR surface impoundments, which greatly increases the potential for birds, amphibians and wildlife to be injured by these "attractive nuisances." CCR impoundments often create habitats attractive to many species of wildlife.[870] Landscape features of CCR impoundments often include wooded edges, open herbaceous areas, and open water and can provide nesting habitat for birds (e.g., shrub and tree edges) as well as abundant and diverse prey populations (e.g., insects, amphibians and fish). However, these impoundments may attract wildlife into areas that pose substantial risks to their health because of the CCR contaminants in water, sediment and plants in and around the impoundments. For example, birds attracted to nest around coal ash settling basins may expose their young to contaminants by provisioning them with contaminated food.[871] The accumulation of toxic metals, particularly selenium, in fish, birds, amphibians and mammals that frequent CCR impoundments can adversely affect their development, reproduction, and survival.[872] EPA must examine the level of increased risk posed by the significant increase in the number of impoundments.

E. EPA MUST CONSIDER INCREASED RISK FROM THE SUBSTANTIAL RISE IN THE NUMBER OF UNLINED AND INADEQUATELY-LINED CCR LANDFILLS IDENTIFIED IN THE DATA GATHERED FOR THE ELG RULE.

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[868] Sixty-one percent of industry responders admitted to having only a single liner or less, which excludes *all* composite liners.
[869] *See* Steam Electric Questionnaire, Part D, Pond/Impoundment Systems, Question D4-4.
[870] *See* Rowe, C.L., Hopkins, W.A., Congdon, J.D., 2002. Ecotoxicological implications of aquatic disposal of coal combustion residues in the United States: a review. 80 Environmental Monitoring and Assessment 207.
[871] *See* Hopkins, W.A., Parikh, J.H., Jackson, B.P., Unrine, J. M. 2012. Coal Fly Ash Basins as an Attractive Nuisance to Birds: Parental Provisioning Exposes Nestlings to Harmful Trace Elements. Environmental Pollution 161:170-177.
[872] *Id.*

As a result of industry responses to the ELG questionnaire, the number of known CCR landfills has also increased substantially. The number of industry-identified CCR landfills increased 30 percent from 337 to 437 landfills.[873] Most critically, the ELG data indicate that the number of unlined and inadequately-lined landfills must be taken into account in the CCR risk assessment. While industry claims that 60-62 percent of CCR landfills are lined and about 40 percent are unlined,[874] a closer look at industry responses to the questionnaire indicates that industry has these figures exactly backwards.

The analysis requires a close examination of industry responses. Part F of the ELG questionnaire was distributed to 97 coal and petroleum coke-burning plants, which is a subset of the 504 coal and petroleum coke-burning plants that received the questionnaire.[875] Part F contained detailed questions regarding the use of landfill liners. Each plant was asked first to indicate whether their landfills were lined and, if so, to provide information regarding the type, number and nature of the liner(s).[876] While industry responded that more than 60 percent of the 108 landfills identified were "lined," the liner descriptions tell a much different story. Because EPA did not define "liner," many of the responses included materials that would not be considered to constitute a liner, or certainly not an adequate liner for proper CCW management. For example, layers of purely soil, scrubber sludge, bottom ash, and general fill were considered "liners." Landfills that appear to have been placed on existing ground conditions with no amendment were also considered to have "liners," including undisturbed clay, partial clay, natural clay and natural chinle. When one considers the absence of a constructed liner and removes these types of clearly inadequate liners from the dataset, the percentage of "lined" landfills falls to 39 percent, and 61 percent of landfills can be considered "unlined," or inadequately lined at best.

Furthermore, when one attempts to quantify the number of landfills having composite liners, which were identified in the risk assessment as essential to preventing migration of CCR contaminants, the percentage falls to about 24 percent of the total number of landfills.[877] This estimate is conservative because the questionnaire did not ask responders to identify composite liners. For the purpose of this estimate, all liners employing high density polyethylene or PVC and having more than one liner layer were considered to have a "composite liner."

EPA must take this critical new information into account when revising the CCR risk assessment. Lastly, EPA must also consider the location of the CCR landfills and their proximity to receptors, both human and ecological, as described above for CCR impoundments.

F. EPA MUST REVISE THE RISK SCREENING ASSESSMENT FOR FUGITIVE DUST, BUT MUST NOT MISAPPLY ELG DATA.

EPA stated in the preamble to the proposed ELG rule that new data regarding landfill size from industry responses to the 2010 ELG survey may prompt EPA to refine the screening assessment

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[873] *See* Gradient, Corp. The Implications of US EPA's Notice of Data Availability (August 2, 2013) on the Human and Ecological Risk Assessment of Coal Combustion Waste, August 30, 2013 at 3, *available at* www.regulations.gov.
[874] *Id.* at 5.
[875] 78 Fed. Reg. at 34,443.
[876] *See* ELG Questionnaire, Management Practices for Ponds/Impoundments & Landfills, question F3-8.
[877] *Id.*

of risks posed by inhalation of fugitive dust from coal ash landfills.[878] We addressed the serious shortcomings of the screening assessment in comments submitted in response to the proposed CCR rule.[879] The methodology employed by EPA's 2009 screening risk assessment, entitled *Inhalation of Fugitive Dust: A Screening Assessment of the Risks Posed by Coal Combustion Waste Landfills*,[880] is substantively flawed and considerably underestimated risks to communities near coal ash landfills. Specifically, the 2009 screening risk assessment considered only one source of fugitive dust emissions from coal ash, *i.e.*, wind erosion, and failed to assess the substantial emissions that occur during unloading and grading of the waste as well as from trucks traveling on the deposited waste at the landfill. Further, the 2009 screening risk assessment only considered risks posed by inhalation of fugitive dust particulate matter emitted from coal ash landfills as measured by the potential violation of national ambient air quality standards; it does not assess constituent-based risks, *i.e.*, the effects of toxic trace elements contained in coal combustion waste nor risks posed by levels of radioactive materials found in the ash.

As described in more detail in the letter from Pless, attached as Appendix G, the ELG survey was not designed to contribute meaningful data to the risk screening assessment. EPA notes that the industry survey includes data on hundreds of surface impoundments that are generally smaller than the impoundments used to support the CCR Rule. For purposes of the inhalation screening risk assessment, surface impoundments must be kept separate from landfills because of their different operating characteristics and surface area exposed to wind erosion.[881]

G. EPA MUST CAREFULLY ASSESS ALL ELG DATA THAT RESULTS IN INCREASED RISK TO HUMAN HEALTH AND THE ENVIRONMENT AND REVISE THE CCR RISK ASSESSMENT ACCORDINGLY.

1. *Lack of all safeguards must be factored into the final risk assessment*

The ELG questionnaire contains information regarding use of safeguards, in addition to liners, such as caps, groundwater monitoring and leachate collection systems at CCR landfill and surface impoundments.[882] Failure to use these safeguards greatly increases the risk of release of hazardous constituents and/or the likelihood of remediation before toxic chemicals meet receptors or enter drinking water. EPA must determine the extent to which both existing and closed CCR disposal units are employing critical safeguards and factor this information into the final risk assessment. In addition, the data regarding closed units must be used in the risk assessment to determine the relative risk posed by legacy waste units. For example, according to

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[878] 78 Fed. Reg. at 34,442.

[879] Petra Pless, Pless Environmental, Inc., Letter to Eric Schaeffer, Environmental Integrity Project, Re: Review of EPA's Inhalation of Fugitive Dust: A Screening Assessment of the Risks Posed by Coal Combustion Waste Landfills, November 16, 2010; available at http://www.regulations.gov/contentStreamer?objectId=0900006480cce734&disposition=attachment&contentType=pdf.

[880] Inhalation of Fugitive Dust: A Screening Assessment of the Risks Posed by Coal Combustion Waste Landfills

[881] http://www.epa.gov/wastes/inforesources/pubs/training/ldu05.pdf.

[882] *See, e.g.,* Steam Electric Questionnaire, Part F. Management Practices for Ponds/Impoundments and Landfills, F3-8, F3-9, F3-11.

the ELG data, while 70 percent of operating landfills have some sort of liner, 55 percent of closed landfills have absolutely no liner.[883]

2. *The significant increase in the number of CCR damage cases demonstrates the validity of the high risk findings of the draft risk assessment, particularly as it relates to arsenic.*

Data made available for the proposed ELG Rule demonstrates that the risks to human health and the environment from disposal of coal ash have increased throughout the United States. The docket for the ELG Rule included a document, entitled *Final Determination of Identified Proven Damage and Recently Alleged Damage Cases*, in which EPA confirms that there are 38 proven and 95 potential coal ash damage cases.[884] This represents an additional 18 proven and 49 potential coal ash damage cases than previously confirmed by EPA in its proposed 2010 CCR rule, nearly doubling the number of confirmed damage cases and more than doubling the number of potential damage cases.[885] This new information should be incorporated into EPA's draft CCR risk assessment and factored into EPA's decision-making process on the CCR disposal rule in order to properly account for the increased risks of current disposal practices.

Surprisingly, the preamble to the ELG Rule did not mention the 68 new damage cases, although EPA did indicate that new data relating to CCR were available in the docket. While ignoring the greater evidence of damage, EPA specifically noted that the new information on size and management practices at coal ash disposal units – should serve to "lower the CCR rule risk assessment results."[886] EPA, however, must consider the evidence in the record, which demonstrates that damage has in fact occurred at far more sites than previously acknowledged. Such evidence of damage provides strong support for a RCRA Subtitle C disposal rule.

EPA should use all of the new data made available by the ELG docket regarding potential risks to human health and the environment from coal ash disposal sites to prepare both its ELG and CCR rule. The Agency must not arbitrarily and capriciously ignore evidence of real world harm at dozens of new sites nationwide.

3. *EPA's CCR impoundment assessment reports revealed poor operation and maintenance practices at a large percentage of CCR impoundments.*

As described in comments submitted to EPA pursuant to the CCR NODA,[887] and further discussed below, EPA's impoundment assessment reports,[888] which assessed the structural

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[883] *See, e.g.*, Steam Electric Questionnaire, Part F. Management Practices for Ponds/Impoundments and Landfills.
[884] EPA, *Final Determination of Identified Proven Damage and Recently Alleged Damage Cases [DCN SE01966]*, Docket No. EPA-HQ-OW-2009-0819-2212.
[885] *See* Environmental Integrity Project, "EPA Confirms 18 New Coal Ash Pollution Sites - 15 Identified by Environmental Integrity Project, Agency identifies "Potential" damage at 49 more locations (Aug. 8, 2013), *available at*
http://www.environmentalintegrity.org/news_reports/documents/2013.08.12DamageCase_Portfolio_REVISED.pdf.
[886] 78 Fed. Reg. at 34,442.
[887] Comments of Earthjustice et al. to U.S. EPA, Office of Resource Conservation and Recovery, Notice of Data Availability and Request for Comment (Coal Ash NODA), 78 Fed. Reg. 46,940 (Aug. 2, 2013) (comments filed Sept. 3, 2013) (Document ID No. EPA-HQ-RCRA-2012-0028-0111).

integrity of more than 500 CCR impoundments, revealed significant problems at a large number of potentially dangerous dams. The assessments documented a high level of risk posed by numerous high and significant hazard dams that either were found not to have factors of safety[889] that met federal standards or had not conducted sufficient analyses to determine such factors. Of the 516 assessments completed, only 41 percent of the dams (214 dams) were rated "satisfactory," and 59 percent were rated "poor" or "fair." In fact, 80 high and significant hazard dams were found to be in poor condition.[890] In addition, the much more detailed assessments conducted on the 24 TVA dams, which involved in-depth geotechnical analysis of each dam, revealed that half of the dams were in poor condition, in danger of failure and required repair to ensure structural stability. If equivalent analyses were performed on each of the 516 dams inspected by EPA, it is likely that many more dams would have been found in conditions similar to the TVA dams. These comments also incorporate by reference the comments by former MHSA Director, Jack Spadaro, submitted by Commenters as an exhibit to this letter.

H. EPA DID NOT ACCURATELY DETERMINE ALL THE POTENTIALLY IMPACTED RECEIVING WATERS FOR SOME COAL PLANTS.

EPA's "List of Coal Plant and Closest Receiving Water" purports to link each coal plant with the closest receiving water body. EPA's list, however, does not always include all receiving waters associated with a coal plant. EPA states "EPA created a list linking the location of each coal plant with the closest receiving water body for evaluating surface water risks as well as human health risks."[891] Our review of a handful of National Pollutant Discharge Elimination System (NPDES) permits and applications reveal that EPA's list does not include all receiving waters for some plants.[892]

We reviewed 36 NPDES permits and found that EPA did not list all receiving waters for 13 of these plants.[893] For example, EPA's list states that the Ohio River is the sole receiving water for the W. H. Zimmer plant. However, the permit states that the plant discharges into the Ohio River, Maple Creek, and Little Indian Creek.[894] A list of the 36 plants reviewed and additional receiving waters for the 13 plants is submitted as an exhibit to this comment letter.

These omissions are significant and would likely impact the risk assessment by erroneously lowering risk levels. Large rivers have more capacity to dilute toxic pollution from coal combustion waste impoundments and landfills. Toxic pollution in small streams and creeks will result in higher concentrations of selenium, cadmium, and other pollutants that are toxic to aquatic life in minute concentrations. In addition, humans recreating in and around these smaller water bodies will also face a greater risk of adverse health effects from exposure to higher concentrations of coal combustion waste pollution. In order to evaluate the risks of coal

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[888] *See* http://www.epa.gov/osw/nonhaz/industrial/special/fossil/surveys2/index.htm.
[889] Minimum stability standards require that impoundments maintain a Factor of Safety of at least 1.5, measured by dividing the strength of the dam by the driving force of its encapsulated material.
[890] *See* Earthjustice NODA comments for complete discussion.
[891] 78 Fed. Reg. 46,940, 46,943 (Aug. 2, 2013).
[892] *See* exhibit submitted with this comment letter.
[893] *Id.*
[894] *See* Ohio Envtl. Prot. Agency, Authorization to Discharge Under the National Pollutant Discharge Elimination System for Duke Energy Ohio, Inc. for Discharges from the William H. Zimmer Station (July 1, 2010).

combustion waste disposal in a meaningful way, EPA must account for surface water loadings in all receiving waters. Thus, EPA should review the NPDES permit and application for *each* coal plant to ensure that all receiving water bodies are identified and taken into account in the risk assessment.

XVI. THE ELG RULE DOES NOT ELIMINATE THE NEED FOR STRINGENT CCR DISPOSAL RULES UNDER RCRA

While Options 4 and 5 of the ELG rule are critical steps to controlling the liquid discharges from coal-burning power plants, EPA must not stop there—the Agency must proceed to finalize a coal ash rule as soon as possible. The most stringent options in the proposed ELG rule require conversion to dry handling of fly ash and bottom ash and the treatment of FGD wastewater, and thus would eliminate the discharge of billions of gallons of toxic wastewater to our rivers and streams each year, as well eliminate the disposal of additional liquid waste in more than 1,000 largely unlined or inadequately-lined ash and sludge impoundments. While these are essential and long overdue steps toward protecting the health and the environment of communities living downstream of coal plants, the rule does not begin to address many additional health and environmental threats posed by coal ash. Specifically, the ELG rule *does not address* safe closure of the thousand leaking and potentially unstable coal ash impoundments nor does it address monitoring and cleanup of contaminated groundwater, control of toxic dust, siting and construction of engineered landfills or maintenance of financial assurance for toxic spills and dump closures. Federally enforceable minimum standards under RCRA are needed to complement the strongest ELG option, and together they can address the toxic pollution from the hundreds of polluting coal-burning power plants.

Assuming, as discussed in Section X, that EPA addresses structural stability requirements for CCR impoundments under specific, timely and enforceable BMPs, the following critical gaps still need to be addressed by an enforceable federal coal rule under RCRA as soon as possible.

A. THE AGENCY'S WEAK OPTIONS IN THE ELG RULE WILL GUARANTEE CONTINUED RELEASE OF HAZARDOUS SUBSTANCES FROM LEGACY WASTEWATER, EXISTING SURFACE IMPOUNDMENTS AND NEW SURFACE IMPOUNDMENTS.

If EPA fails to finalize Options 4 or 5 and to address legacy wastewater, releases of hazardous substances from CCR surface impoundments will continue to damage groundwater and surface water and adversely impact human health and the environment, absent strong RCRA regulations. Continued operation of CCR impoundments requires stringent ground water monitoring and corrective action standards when contaminants are detected. Furthermore, the construction of additional new impoundments is likely to continue under EPA's weaker options, and currently there are no federal CCR standards in place to require adequate design and maintenance. The widespread absence of adequate state regulations governing CCR disposal makes the establishment of minimum federal standards absolutely essential to protection of health and the environment.[895]

B. UNDER ALL OPTIONS, RCRA CLOSURE AND POST-CLOSURE STANDARDS FOR CCR SURFACE IMPOUNDMENTS MUST BE REQUIRED TO ENSURE PROTECTION OF HUMAN HEATH AND THE ENVIRONMENT.

EPA's establishment of dry handling as BAT for fly ash transport water will render the nation's enormous fleet of coal ash impoundments obsolete as disposal units. EPA, however, has not included the dewatering, secure closure, and post-closure monitoring of these units as part of the ELG rule. EPA should establish these requirements as BMPs as discussed in Section X, *supra*.

Without federal standards for safe closure and post-closure care of CCR impoundments, EPA's rule is not protective. EPA must establish federal standards under the CWA and/or RCRA to address the huge threat posed by inactive dumps to public safety, human health and the environment.

1. Federal regulations are necessary because state laws fail to require safe closure and post-closure of CCR impoundments.

Almost universally, state laws are grossly deficient and cannot ensure the safety of retired coal ash impoundments. We reviewed the adequacy of closure regulations for coal ash impoundments in 37 states, which together comprise over 98 percent of all the coal ash generated nationally.[896] State closure regulations were evaluated against four basic closure requirements that EPA proposed in its 2010 CCR rule.[897] These included:(1) submission of a closure plan to the state prior to closure; (2) elimination of free liquids by removing liquid wastes or solidifying the remaining wastes; (3) stabilization of remaining wastes to a bearing capacity sufficient to support the final cover; and (4) construction of final cover that has a permeability less than or equal to the permeability of any bottom liner system or natural subsoils present, or a permeability no greater than 1 x 10^{-5} cm/sec, whichever is less; and (5) conducting 30 years of post-closure groundwater monitoring. Table 1 of Exhibit XII-9, State Closure Requirements for Coal Ash Surface Impoundments," contains the results of the 37-state review.[898]

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[895] Earthjustice has previously submitted detailed analysis of the deficiencies of state CCR programs. *See* Comments of Earthjustice et al. to U.S. Environmental Protection Agency ("U.S. EPA"), Office of Resource Conservation and Recovery, Hazardous and Solid Waste Management System; Identification and Listing of Special Wastes; Disposal of Coal Combustion Residuals From Electric Utilities, 75 Fed. Reg. 35,128 (proposed June 21, 2010) (comments filed Nov. 19, 2010) (Document ID No. EPA-HQ-RCRA-2009-0640-6315) and Comments of Earthjustice et al. to U.S. EPA, Office of Resource Conservation and Recovery, Notice of Data Availability and Request for Comment (Coal Ash NODA), 76 Fed. Reg. 63,252 (Oct. 12, 2011) (comments filed Nov. 14, 2011) (Document ID No. EPA-HQ-RCRA-2011-0392).

[896] Alabama, Arizona, Colorado, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Montana, Nevada, New Hampshire, New Jersey, New Mexico, New York, North Carolina, North Dakota, Ohio, Oklahoma, Pennsylvania, South Carolina, South Dakota, Tennessee, Texas, Utah, Virginia, Washington, West Virginia, Wisconsin and Wyoming.

[897] *See* Hazardous and Solid Waste Management System; Identification and Listing of Special Wastes; Disposal of Coal Combustion Residuals from Electric Utilities, 75 Fed. Reg. 35128, 35252 (proposed June 21, 2010).

[898] The results are based on a review of each state's administrative rules, statutes, and representations to the EPA regarding regulatory programs for CCR impoundments. For each state, the survey first indicates whether there are

None of the 37 states reviewed impose all five of the basic CCR impoundment closure requirements that EPA outlined in the proposed CCR rules. Only three states, Michigan, Louisiana, and New York, impose or otherwise satisfy[899] four out of the five requirements. Two states impose three of the requirements. Ten states impose just one or two of the requirements. The remaining 22, or nearly than 60% of the states surveyed, do not impose any of these five basic closure requirements. See Figure 1, below.

These results are not surprising because only 19 out of the 37 states surveyed have *any* solid waste regulations on the books that are specifically applicable to CCR impoundments.[900] Among those 19 states that regulate CCR impoundments, the most common of the five basic closure requirements is the duty to submit a closure plan. Yet more than 30 percent, or 6 of the 19, fail to require a closure plan. The second most common closure requirement is a final cover meeting or exceeding the permeability standards EPA proposed. Eight states require adequate final cover. However, another eight states fail to require any cover whatsoever for CCR impoundments, while three states fail to specify adequate permeability.[901] The remaining three requirements were even less prevalent. Only five states require groundwater monitoring for the proposed 30-year period. By far, the least common closure requirements are dewatering and waste stabilization. Only two states require that CCR impoundments be dewatered, and only one state explicitly requires that CCR impoundment wastes be stabilized to the extent necessary to support the required final cover.

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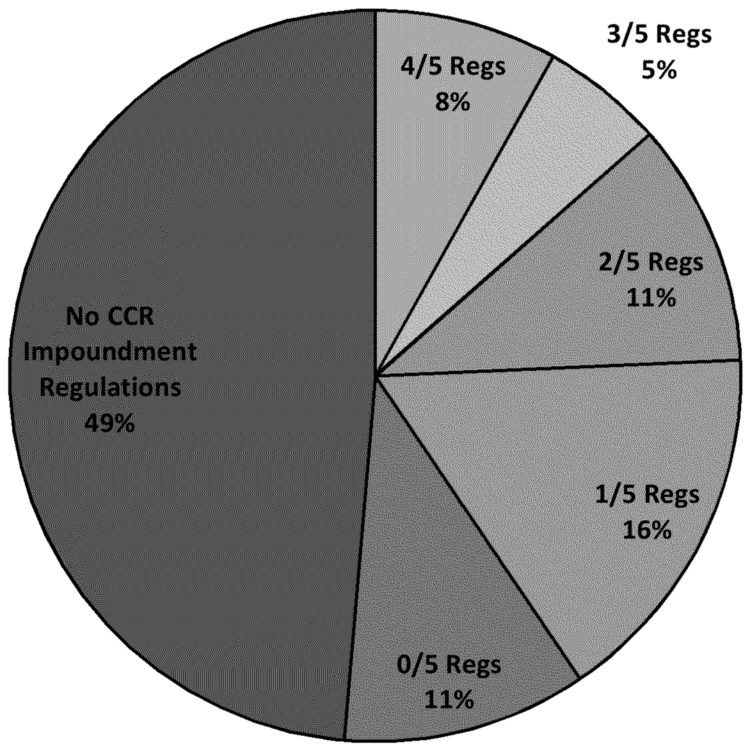
any regulations in place applicable to CCR impoundments. Next, the survey indicates whether the regulations identified, if any, impose each of the four closure requirements listed above. A state is identified as imposing a requirement only if state law makes that requirement generally applicable to CCR impoundments, rather than a narrow subset of CCR impoundments. A state is identified as imposing a requirement even if its administrators may exercise broad discretion in exempting individual CCR impoundments from that requirement, if it would otherwise apply by default. This methodology conservatively credits states with imposing requirements that may rarely be enforced.

[899] New York actually imposes only one of the five requirements that are the focus of this review, but is credited here as imposing four because it is the only state that requires operators to remove all waste and contaminated soil from CCR impoundments upon closure. EPA proposed complete waste removal as an acceptable alternative to closure with CCRs in place. *See* Disposal of Coal Combustion Residuals from Electric Utilities, 75 Fed. Reg. at 35253. As a result, New York is treated as having satisfied the Dewatering, Waste Stabilization, and Impermeable Final Cover criteria that would apply to impoundments closed with CCRs in place.

[900] These states may require NPDES permits for discharges from the impoundments, but the CCR impoundments themselves are not regulated as solid waste disposal units, and therefore the state solid waste disposal rules are not applicable.

[901] Iowa, Missouri, and South Dakota. See Table 5, "Impermeable Final Cover" for these states.

Fig. 1. Thirty-Seven State Review: Five Basic Closure Regulations for CCR Impoundments



2. *The magnitude of the risk requires immediate EPA action.*

According to EPA, there are 1070 retired and operating CCR impoundments.[902] The data submitted by utilities pursuant to the ELG Questionnaire indicate that the nation's operating impoundments together impound more than 47.4 billion cubic feet of wastewater and coal combustion waste slurry. This number greatly underestimates the total because the volume of over 1000 impoundments was claimed as CBI.[903] More precisely, according to the Toxic Release Inventory, in 2010 alone, power plants reported using impoundments to dispose of CCR containing 112.8 million pounds of toxic metals or metal compounds, a category that includes arsenic, chromium, lead, and other pollutants that are hazardous in small concentrations and difficult to remove from the environment once released.[904] These impoundments are largely unlined, and many have been used for over four decades as dumps for the toxic mixture.

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[902] 78 Fed. Reg. at 34,516.

[903] *See* responses to Steam Electric Questionnaire, Part D, Pond/Impoundment Systems, Question D4-3.

[904] Environmental Integrity Project, Disposal in Coal Ash Ponds Increases 9% in 2010, January 5, 2012, *available at* http://www.environmentalintegrity.org/01_05_2012.php.

Unfortunately, this immense quantity of toxic material does not remain contained in these aging dumps. Since 2002, six major spills have occurred at five different plants: Plant Bowen, Georgia;[905] Martins Creek Station, Pennsylvania;[906] Oak Creek Plant, Wisconsin;[907] Eagle Valley Generating Station, Martinsville, Indiana (two dam breaks);[908] and the Kingston Fossil Plant, Tennessee.[909] In addition, the number of EPA-acknowledged damage cases from coal ash disposal has jumped nearly three-fold from 47 sites in 2000 to 133 sites in 2013.[910] Many of these damage cases involved the leaking or failure of CCR surface impoundments. These toxic dumps will continue to leak hazardous pollutants and to threaten widespread devastation until properly closed. Even after closure, monitoring must occur for decades to ensure the units' integrity.

In the absence of federal or state regulations requiring safe closure, the unthinkable can occur. This is illustrated by the intentional breaching of five CCR impoundments at the NIPSCO D.H. Mitchell Generating Station in Gary, Indiana.[911] In 2002, following the shut-down of the plant, NIPSCO released all liquid coal ash waste from five separate coal ash impoundments by breaching the impoundment walls. Four of the impoundments had been operating since 1956, and the fifth impoundment was constructed in 1969. According to an environmental assessment performed by an EPA contractor in 2011, the impoundment walls were breached in four places and "all of the wastewater discharged to the Impoundments was discharged through the NPDES outlet to Lake Michigan."[912] It is estimated that approximately 134,000 tons of coal ash slurry and wastewater was released into the lake.[913] At the time of the 2011 inspection, ash residue was observed, but no liquid remained in the unlined impoundments and precipitation that currently enters the impoundments "appears to infiltrate the ground" through the ash.[914] Without protective regulations, releases of large quantities of toxic waste may occur at hundreds of coal ash impoundments. The strongest options in the ELG rule may have the effect of discontinuing the use of existing impoundments and avoiding the creation of new ones, but nothing in the proposed ELG rule requires the safe and systematic retirement of existing impoundments as necessary to safeguard our communities and environment.

C. EPA'S ELG REGULATORY OPTIONS WILL REQUIRE THE CONSTRUCTION OF NEW CCR LANDFILLS THAT MUST BE DESIGNED, CONSTRUCTED AND MAINTAINED TO PROTECT HUMAN HEALTH AND THE ENVIRONMENT.

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905 *See* http://clatl.com/atlanta/georgia-power-ash-and-arsenic-spill-bad-news/Content?oid=1237902
906 75 Fed. Reg. at 35,238.
907 *See* http://dnr.wi.gov/topic/Spills/documents/oakcreek/noaa-finalreport.pdf.
908 *See* U.S. Envt'l Prot. Agency, Coal Combustion Residuals Impoundment Assessment Reports: Summary Table for Impoundment Reports, (July 19, 2013), *available at* http://www.epa.gov/osw/nonhaz/industrial/special/fossil/surveys2/.
909 78 Fed. Reg. at 34,466.
910 *See* EA, Appendix A.
911 *See* Final Round 10 Dam Assessment Report: NIPSCO DH Mitchell Generating Station Coal Ash Impoundments, GZA GeoEnvironmental, Inc,, August 17, 2012, *available at* http://www.epa.gov/osw/nonhaz/industrial/special/fossil/surveys2/nipsco_mitchell_final.pdf.
912 *Id.* at 2.
913 *Id.* at 4.
914 *Id.* at 6.

The establishment of dry handling as BAT for fly ash transport water will necessitate the disposal of voluminous quantities of fly ash in landfills rather than surface impoundments. Similarly, dry handling of bottom ash and the solids produced in the chemical precipitation, biological treatment, and evaporation systems for FGD wastewater, will increase the total solid waste generated by the industry. Therefore, EPA must establish immediately the concomitant design and maintenance standards essential for the construction and safe operation of engineered coal ash landfills under RCRA. Currently, the majority of states do not require basic protective requirements such as composite liners, leachate collection systems, groundwater monitoring, financial assurance, closure and post-closure standards and corrective action at all new coal ash landfills. The construction of CCR landfills without these basic standards would undo much of the anticipated benefit of the ELG rule.

XVII. EPA FAILED TO COMPLY WITH EXECUTIVE ORDER 12898 BY FAILING TO IDENTIFY AND ADDRESS SIGNIFICANT DISPARATE IMPACTS OF THE ELG OPTIONS

EPA failed to conduct the required inquiry into whether its regulatory options have a disproportionately high and adverse health or environmental impact on communities of color and low-income populations. The Agency's cursory inquiry focused on only one adverse impact of pollution discharges (consumption of contaminated fish) and failed entirely to evaluate the health and environmental harms suffered by communities proximate to the source of pollution. The abbreviated inquiry does not satisfy the Executive Order nor is it consistent with the environmental justice assessment conducted by the Agency for its 2010 proposed CCR rule on identical pollution sources.[915] EPA's indefensibly narrow environmental justice analysis represents substantial noncompliance with the Executive Order that must be rectified.

Under Executive Order 12898, each Federal agency must make achieving environmental justice part of its mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of its programs, policies, and activities on minorities and low-income populations.[916] EPA, however, summarily sidestepped the directive of Executive Order 12898 by concluding that its environmental justice analysis "indicates that minority and low-income communities are expected to benefit as much as anyone from the proposed ELGs." This statement entirely misconstrues the mandate of Executive Order 12898. EPA performed only a perfunctory analysis to determine whether a very broad population benefitting in one specific way from pollution reductions would exclude minority and low-income populations. The Agency did not even begin to examine the widely divergent regulatory options in the ELG rule and consider whether the outcomes of those options would have a disproportionate impact considering the many harms presented by coal-burning power plants to directly impacted communities.

[915] *See* CCR RIA at 216-226.

[916] Executive Order 12898, Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations (59 Fed. Reg. 7629, Feb. 16, 1994). *See also* Interim Guidance on Considering Environmental Justice During the Development of an Action (July 2010), *available at* http://www.epa.gov/environmentaljustice/resources/policy/considering-ej-in-rulemaking-guide-07-2010.pdf.

The decision currently before EPA is not whether to promulgate an ELG rule, but to determine the precise coverage and breadth of a final ELG rule. According to analyses of the populations proximate to power plants recently completed by EPA, this decision assuredly affects low-income populations disproportionately. EPA must therefore identify any disproportionate impact on minority and low-income populations that results *from the Agency's choice of one option over another*. According to the Executive Order, if disparate impacts are identified, EPA must address those impacts. Most importantly, the Agency must make achieving environmental justice a factor in its decision to choose one option over another. Unfortunately EPA has barely begun the analysis required by the Executive Order.

C. EPA FAILED TO COLLECT AND EVALUATE ENVIRONMENTAL JUSTICE DATA AS REQUIRED BY EXECUTIVE ORDER 12898.

The information collection and analysis mandates of Executive Order 12898 are crystal clear. Section 3-302(b) of Executive Order 12898 requires Federal agencies to collect and evaluate environmental justice data for areas surrounding facilities or sites expected to have "substantial environmental, human health, or economic effect" on local populations when such facilities or sites become subject to "substantial" Federal environmental action:

> In connection with the development and implementation of agency strategies in section 1-103 of this order, each Federal agency, whenever practicable and appropriate, shall collect, maintain and analyze information on the race, national origin, income level, and other readily accessible and appropriate information for areas surrounding facilities or sites expected to have substantial environmental, human health, or economic effect on the surrounding populations, when such facilities or sites become the subject of a substantial Federal environmental administrative or judicial action. Such information shall be made available to the public unless prohibited by law.[917]

Certainly the ELG rule is a substantial federal environmental action likely to have a substantial environmental, health or economic effect on populations proximate to the power plant. However, EPA did not conduct any environmental justice analyses of populations surrounding the hundreds of coal-burning plants subject to the ELG rule. Instead, EPA performed a birds-eye evaluation of the make-up of the population located within a 100-mile downstream reach of the plants, focusing on only one aspect of harm.[918]

EPA described their sole, specific inquiry for their environmental justice analysis:

> To address the EJ implications of the proposed ELGs, EPA analyzed the demographic characteristics of the populations currently exposed to these discharges through consuming self-caught fish from receiving reaches (i.e., populations located within 100 miles of the affected reaches also referred to as the "benefit regions" in the rest of this discussion) to determine whether minority and/or low-income populations incur disproportionally high environmental

[917] *Id.* at Section 3-302(b).
[918] RIA at 10-2.

impacts or are disproportionally excluded from realizing the benefits of this proposed regulation.[919]

EPA's exceedingly narrow scope of inquiry does not meet the requirements of the Executive Order. The Agency's analysis does not in any way evaluate effects on the health, environment or economy of populations "surrounding" the power plants, nor does EPA evaluate whether these impacts will be felt disproportionately by communities of color or low-income communities.

D. EPA MUST EVALUATE COMMUNITIES IMMEDIATELY SURROUNDING COAL-BURNING POWER PLANTS FOR DISPARATE IMPACT.

In addition to its general assessment of populations 100 miles from coal-burning power plants, EPA must evaluate populations within 15 miles of all facilities affected by the ELG rule. A 15-mile evaluation is consistent with Superfund's Hazard Ranking System (HRS), which is used to define affected populations at sites having either (a) soil contamination only (1 mile), (b) groundwater and/or airborne contamination (4 miles), or (c) surface water contamination (15 miles downstream).[920] Because the ELG rule will impact waste disposal practices at coal-burning power plants that adversely affect soil, air and groundwater, it is appropriate to examine populations within a four-mile radius, as well as 15 miles downstream.

This approach is consistent with EPA's 2010 environmental justice analysis for the proposed CCR Rule completed pursuant to Executive Order 12898. EPA's 2010 analysis was based on "Zip Code Tabulation Areas (ZCTAs).[921] EPA used ZCTAs as the geographic basis for the analysis because it offered a land area equivalent to a five-mile radial distance. EPA collected 2000 census data in the ZCTAs for 464 coal burning plants. After assessing the extent of minority and low-income populations found in these ZCTAs, EPA concluded that low-income citizens were disproportionately represented in the populations within the four-mile radius of the plants, and therefore the hazards and risk from coal ash landfills and surface impoundments "may have a disproportionately higher effect on low income populations."[922]

Furthermore, EPA's current analysis of fish consumers within 100 miles of power plants cannot capture disproportionate impacts that may be occurring locally. It is essential to perform an accurate and precise assessment because poisoning of fish is particularly unjust for communities that depend heavily on fish for food. According to the National Environmental Justice Advisory Council, families in many communities of color, including African-Americans and Native peoples, rely on fishing to supply basic nutritional needs.[923] Fishing provides an inexpensive and healthful food source, but when fish are contaminated, reliance on fishing for food makes these communities far more vulnerable to water pollution and contaminated fish than the general population.[924] EPA failed to identify environmental justice communities proximate to power

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[919] *Id.* at 10-2.
[920] HRS is available at http://www.epa.gov/superfund/programs/npl_hrs/hrsint.htm.
[921] EPA, CCR RIA at 217.
[922] 75 Fed. Reg. at 35230.
[923] National Environmental Justice Advisory Council, Fish Consumption and Environmental Justice iii-iv (2002), *available at* http://www.epa.gov/environmentaljustice/resources/publications/nejac/fish-consump-report_1102.pdf.
[924] *Id.*

plants that rely on such food sources and who would be disproportionately impacted by options in the ELG rule that fail to control pollution sources.

EPA therefore must examine the surrounding communities, as required by the Executive Order, and investigate with much greater diligence whether harm to health, the environment and the economies of these communities are disproportionately impacted.

E. EPA MUST EVALUATE ALL REGULATORY OPTIONS IN THE PROPOSED ELG RULE TO DETERMINE WHETHER THE OPTIONS RESULT IN DISPROPORTIONATE EFFECTS ON COMMUNITIES OF COLOR AND LOW-INCOME COMMUNITIES.

The range of options proposed by EPA creates dramatically different outcomes in protection of health and the environment for environmental justice communities. Consequently, EPA must evaluate its range of eight options and identify such disparate impacts. Below, we highlight three examples of disproportionate impact that must be analyzed and addressed, according to the requirements of the Executive Order.

1. Reliance on BPJ in Options 3a and 3b will have a disparate impact on communities of color and low-income populations.

EPA must evaluate the environmental justice implications of two of its preferred options, 3a and 3b. As discussed previously, Options 3a and 3b (for plants with less than 2,000 MW wet-scrubbed capacity) would leave effluent limits to be set on a case-by-case basis.[925] The practical implications of EPA's failure to set ELGs for FGD wastewater are enormous. The record shows that local permitting authorities do not rigorously apply best professional judgment for determination of the best available technology for FGD wastewater and coal combustion residuals.[926] EPA, in fact, is well aware that states have failed to establish technology-based effluent limits for these waste streams, as evidenced by the dozens of objection letters issued by EPA regional offices.

Case-by-case BAT determinations are extremely problematic for local communities affected by these discharges who might seek stronger permits. To fully participate in the administrative review process, local groups must pay for legal and technical assistance, including hiring experts to investigate existing technologies and present alternative BAT analyses. Clearly, most impacted local communities lack these kinds of resources. Thus, a critical flaw with relying on case-by-case BPJ determinations is that BAT determinations will vary by jurisdiction and, even within a single jurisdiction, may vary depending on whether a local community is able to participate in the administrative process and has the resources to advocate for protective permit limits.

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[925] 78 Fed. Reg. at 34,458, Table VIII-1.

[926] *See* Closing the Floodgates, (finding that out of 274 power plants discharging wastewater, only 86 had at least one limit on arsenic, boron, lead, mercury, cadmium, or selenium; 255 plants lacked any limits on arsenic; 235 plants lacked any limits on mercury; 232 lacked limits on selenium; and nearly 40 percent did not even require monitoring for any of these pollutants).

Communities without resources to engage in the resource-intensive permitting process are much less likely to be able to compel the permitting authority to issue a permit containing strong BAT-based limits. Consequently it is likely that Options 3a and 3b would provide less protection to under-resourced communities, such as low-income communities and communities of color, then a uniform national standard. The Executive Order therefore requires EPA to fully evaluate the impact on these communities of the reliance on BPJ in its environmental justice analysis.

1. Proposed regulatory options that permit the continued use of coal ash surface impoundments will have disparate impact on communities of color and low-income populations.

As EPA demonstrated in its environmental justice analysis for the 2010 proposed CCR rule, coal ash landfills and surface impoundments are more often located in low-income communities and therefore may have a disproportionately higher impact on this population. Further, Earthjustice's own environmental justice analysis in 2010 of the proposed CCR rule also found coal-burning power plants disproportionately located in impoverished areas. Earthjustice found that almost 70 percent of coal ash impoundments in the United States are in areas where household income is lower than the national median.[927] Earthjustice also found that, of the 181 ZIP codes nationally that contain coal ash ponds, 118 (65.19 percent) have above-average percentages of low-income families.[928] Given the serious health threats posed by coal ash, it is particularly troublesome that coal ash impoundments are disproportionately located in low-income communities, where residents are more likely to rely on fish consumption, groundwater supplies and less likely to have access to medical insurance and care. Consequently, ELG options that rely on the continued use of impoundments are likely to disproportionately impact environmental justice populations near the power plants.

Earthjustice also found in its 2010 analysis that the lack of standards for safe operation of surface impoundments was most acute in states where the disproportionate impact for both income and race was greatest for communities living near the impoundments.[929] In addition, Earthjustice found that the largest number of coal ash impoundments were located in states that generally

[927] U.S. Census Bureau, Census 2000 Summary File 3 (SF 3) - Sample Data, All 5-Digit ZIP Code Tabulation Areas (860), Table P53 "Median Household Income in 1999 (Dollars)", available at http://factfinder.census.gov/servlet/DCSubjectKeywordServlet?_ts=307978361769.

[928] U.S. Census Bureau, Census 2000 Summary File 3 (SF 3) - Sample Data, All 5-Digit ZIP Code Tabulation Areas (860), Table P76 "Family Income in 1999" (downloaded June 23, 2009), available at http://factfinder.census.gov/servlet/DownloadDatasetServlet?_lang=en&_ts=263843114140. "Low-income" defined as earning less than $20,000 annually. ZIP codes containing coal ash ponds compared to a national mean percent "low-income" of 12.61%, calculated based on the "Family Income in 1999" dataset; United States Environmental Protection Agency (U.S. EPA). Database of coal combustion waste surface impoundments (2009). Information collected by EPA from industry responses to Information Collection Request letters issued to the companies on March 9, 2009. Sufficient data to determine ZIP code Census Data was available for 511 of the nation's 584 known coal ash impoundments. Many impoundments are adjacent to one another surrounding generating facilities, and are listed with identical geographic coordinates in the EPA data—hence why only 181 ZIP codes contain 511 ash impoundments.

[929] *See* Comments of Earthjustice et al. to U.S. Environmental Protection Agency ("U.S. EPA"), Office of Resource Conservation and Recovery, Hazardous and Solid Waste Management System; Identification and Listing of Special Wastes; Disposal of Coal Combustion Residuals From Electric Utilities, 75 Fed. Reg. 35,128 (proposed June 21, 2010) (comments filed Nov. 19, 2010) (Document ID No. EPA-HQ-RCRA-2009-0640-6315), 195-205.

have the weakest regulations.[930] Because EPA has proposed options that would permit the continued use of surface impoundments, EPA must examine the potential disparate impact on environmental justice communities in light of current state law as well as the options EPA is considering in its proposed CCR rule.

2. *The failure to establish specific and enforceable BMPs for structural stability and closure will have disparate impact on communities of color and low-income populations.*

The failure to require structural stability and closure requirements in BMPs will also have a disproportionate impact on low-income communities. Low-income populations immediately surrounding a coal ash impoundment will be most heavily impacted if impoundments are not required to ensure structural stability or have not been properly closed. Adverse impacts from coal ash surface impoundments on local communities can include seeps of highly polluted, water, groundwater contamination, poisoning of fish, birds, wildlife and livestock that frequent the impoundment, destruction of recreational opportunities in nearby surface waters, depressed property values, fugitive airborne ash, as well as cataclysmic dam failures. Such adverse impacts from inadequately maintained or improperly closed impoundments are potentially severe, and such localized impacts must be examined for their disparate impacts under all ELG options that do not include BMPs addressing such risks.

F. EPA'S ENVIRONMENTAL JUSTICE ANALYSIS IS ARBITRARY AND CAPRICIOUS AND MUST BE REVISED TO EVALUATE ADEQUATELY THE IMPACTS OF THE PROPOSED ELG RULE, AS REQUIRED BY EXECUTIVE ORDER 12898.

Courts have held that an agency's environmental justice analysis is subject to review under the Administrative Procedure Act and can be found arbitrary and capricious.[931] EPA's failure to follow the explicit requirements of Executive Order 12898 to evaluate surrounding communities impacted by the proposed rule or to evaluate the options being considered by the Agency and their impacts on environmental justice communities renders its analysis arbitrary and capricious. EPA must therefore revise the analysis and consider the results of its new environmental justice analysis in its decision making for the final ELG rule.

XVIII. CONCLUSION

For all of the reasons set forth above, and in the appendices and exhibits submitted by Commenters as attachments to this letter, the undersigned Commenters strongly urge EPA to finalize Steam Electric ELGs that fully comply with the Clean Water Act's requirements no later

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[930] *Id.*

[931] *See Communities Against Runway Expansion, Inc. v. FAA*, 355 F.3d 678, 688-689 (D.C. Cir. 2004) (in the context of a challenge to an agency's choice of reference group in the disproportionality analysis, the court ruled that where an agency exercises its discretion to include an environmental justice analysis, it is subject to review under the arbitrary and capricious standard pursuant to the APA*); Coliseum Square Ass'n, Inc. v. Jackson*, 465 F.3d 215 (5th Cir. 2006) (review of agency's consideration of environmental justice appropriate under APA arbitrary and capricious standard).

than May 2014. To satisfy its responsibility under the Clean Water Act to curb dangerous coal plant water pollution and protect public health and our waters, EPA must choose Option 5 or, at a minimum, Option 4 as the basis for the final rule.

Thank you for the opportunity to comment on this rule. If you have any questions about our comments, please contact Thomas Cmar (tcmar@earthjustice.org), Matthew Gerhart (mgerhart@earthjustice.org), or Lisa Evans (levans@earthjustice.org) of Earthjustice (212-845-7387); Casey Roberts of the Sierra Club Environmental Law Program (casey.roberts@sierraclub.org, 415-977-5710); or Jennifer Duggan of the Environmental Integrity Project (jduggan@environmentalintegrity.org, 802-225-6774).

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